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NUREG-0829

Integrated Plant Safety Assessment
Systematic Evaluation Program

San Onofre Nuclear Generating Station, Unit 1

Southern California Edison Company
Docket No. 50-206

Final Report

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

December 1986

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ABSTRACT

The Systematic Evaluation Program was initiated in February 1977 by the U. S. Nuclear Regulatory Commission to review the designs of older operating nuclear reactor plants to reconfirm and document their safety. The review provides (1) an assessment of how these plants compare with current licensing safety requirements relating to selected issues, (2) a basis for deciding on how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety.

This report documents the review of San Onofre Nuclear Generating Station, Unit 1, operated by Southern California Edison Company. The San Onofre plant is one of ten plants reviewed under Phase II of this program. This report indicates how 137 topics selected for review under Phase I of the program were addressed. Equipment and procedural changes have been identified as a result of the review. This report will be one of the bases in considering the issuance of a full-term operating license in place of the existing provisional operating license. This report also addresses the comments and recommendations made by the Advisory Committee on Reactor Safeguards in connection with its review of the draft report issued in April 1985.

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ACRONYMS AND INITIALISMS

ac	alternating current
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safguards
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction, Inc.
API	American Petroleum Institute
ASA	American Standards Association
ASB	Auxiliary Systems Branch
ASME	American Society of Mechanical Engineers
BTP	branch technical position
BWR	boiling-water reactor
CCW	component cooling water
CFR	*Code of Federal Regulations*
CIS	containment isolation system
CSAS	containment spray actuation signal
CV	control valve
CVCS	chemical and volume control system
DBE	design-basis event
dc	direct current
ECCS	emergency core cooling system
ESF	engineered safety feature
FCV	flow control valve
FSAR	Final Safety Analysis Report
FTOL	full-term operating license
FW/SI	feedwater/safety injection
GDC	general design criterion(a)
gpm	gallon(s) per minute
HVAC	heating, ventilation, and air conditioning
HX	heat exchanger
ICSB	Instrumentation and Control Systems Branch
IEEE	Institute of Electrical and Electronics Engineers
IPSAR	integrated plant safety assessment report
IREP	Integrated Reliability Evaluation Program
LCV	level control valve
LER	licensee event report
LOCA	loss-of-coolant accident
LOP	loss of power
MEB	Mechanical Engineering Branch
MLLW	mean low level water datum
MOV	motor-operated valve
MPA	multiplant action
mph	miles per hour
MWe	megawatt-electrical
MWt	megawatt-thermal
NRC	U. S. Nuclear Regulatory Commission
OMS	overpressurization mitigation system
ORNL	Oak Ridge National Laboratory

PMF	probable maximum flood
PMP	probable maximum precipitation
PNO	preliminary notification of occurrence
POL	provisional operating license
POV	power-operated valve
PRA	probabilistic risk assessment
psi	pound(s) per square inch
psig	pound(s) per square gage
PWR	pressurized-water reactor
RAB	reactor auxiliary building
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RETS	Radiological Effluent Technical Specifications
RG	regulatory guide
RHR	residual heat removal
RPS	reactor protection system
RSB	Reactor Systems Branch
RWST	refueling water storage tank
SALP	systematic assessment of licensee performance
SAR	safety analysis report
SCE	Southern California Edison Company
SEP	Systematic Evaluation Program
SER	safety evaluation report
SI	safety injection
SIAS	safety injection actuation signal
SIS	safety injection system
SLSS	safeguards load sequencer system
SONGS	San Onofre Nuclear Generating Station
SRP	Standard Review Plan
SWC	salt water cooling
SWGR	switchgear
SWR	service water reservoir
T_{ave}	average temperature
TAP	Task Action Plan
TMI	Three Mile Island
TS	Technical Specifications
UHS	ultimate heat sink
UPS	uninterruptible power supply
USI	unresolved safety issue
VCT	volume control tank

SUMMARY

The Systematic Evaluation Program (SEP) was initiated by the U.S. Nuclear Regulatory Commission (NRC) to review the designs of older operating nuclear reactor plants to reconfirm and document their safety. The review provides (1) an assessment of the significance of differences between current technical positions on safety issues and those that existed when a particular plant was licensed, (2) a basis for deciding how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety.

The review compared the as-built design with current review criteria in 137 different areas defined as "topics." The "Definition" and other information for each of these topics appear in Appendix A. During the review, 48 of the topics were deleted from consideration under the SEP because a review was being made under other programs (Unresolved Safety Issue (USI) or Three Mile Island (TMI) Action Plan Tasks), or the topic was not applicable to the plant; that is, the topic was applicable to boiling-water reactors (BWRs) rather than to pressurized-water reactors (PWRs) or the items to be reviewed under that topic did not exist at the site. The topics deleted because they were being reviewed under either the USI or TMI programs are listed in Appendix B, and the topics deleted because they did not apply to the plant are listed in Appendix C.

Of the original 137 topics, 89 were, therefore, reviewed for San Onofre Nuclear Generating Station Unit 1; of these, 53 met current criteria or were acceptable on another defined basis. References for correspondence pertaining to safety evaluation reports (SERs) for each of the 89 topics appear in Appendix E.

The review of the remaining 36 topics found that certain aspects of plant design differed from current criteria. These topics were considered in the integrated assessment of the plant, which consisted of evaluating the safety significance and other factors of the identified differences from current design criteria to arrive at decisions on whether modifications were necessary from an overall plant safety viewpoint. To arrive at these decisions, engineering judgment was used as well as the results of a limited probabilistic risk assessment study. This study and staff comments are in Appendix D.

Table 4.1 summarizes the staff's positions reached in the integrated assessment. In general, these fell into one or more of the following categories: (1) equipment modification or addition, (2) procedure development or Technical Specification changes, (3) refined engineering analysis or continuation of ongoing evaluation, and (4) no modifications necessary.

Safety improvements are being planned as a result of the integrated assessment and are listed below. Some safety improvements have already been implemented by the licensee. These are discussed in Sections 3 and 4 but are not listed below. The following descriptions summarize the corrective actions addressed by the integrated assessment. The sections in this report relating to the issue are given in parentheses.

SAFETY IMPROVEMENTS AGREED TO AND TO BE IMPLEMENTED BY THE LICENSEE AS A RESULT OF SEP

These improvements fall into three categories. The first category comprises hardware modifications or additions that the licensee has agreed to make and that are required by the NRC. The second category comprises procedural or Technical Specification changes that become part of the operating license. The third category comprises additional engineering analysis followed by corrective measures where required. These three categories are listed below, and the issues are discussed in sections of this report given in parentheses.

Category 1, Equipment Modifications or Additions

(1) Install motor-driven auxiliary feedwater pump train (4.28.3 and 4.36).

(2) Implement modifications to undervoltage protection logic, including Technical Specifications (4.29.1).

(3) Install dedicated shutdown system (diesel generator and switchgear) for fire protection (4.32.3 and 4.34).

(4) Provide automatic termination of injection flow on low tank level and a backup to the tank level indication (4.24).

Category 2, Technical Specification Changes and Procedure Development

The staff's position regarding Technical Specification changes is that the proposed changes may be submitted all together following the completion of the integrated assessment. The licensee should submit, within 90 days after the issuance of the Final Integrated Plant Safety Assessment Report, a request for an amendment of the operating license to change the facility Technical Specifications.

(1) Provide enhanced surveillance program for the water intake structure and incorporate other identified changes in the water control structure surveillance program (4.7).

(2) Provide Technical Specifications for operability of leakage detection systems (4.18.1.2).

(3) Provide procedures for handling potential failures of the leak detection systems following a seismic event (4.18.1.3).

(4) Provide Technical Specifications for the overpressure mitigation system (4.21.2).

(5) Develop a periodic inspection program for containment coatings (4.22).

(6) Modify sequencer test procedures to use door control panel lights (4.23.1.2).

(7) Modify procedures to address need for operator action to ensure diesel generator cooling following a loss of offsite power (4.23.1.4).

(8) Provide administrative controls and/or locking devices for refueling water supply line branches (4.23.7.1).

(9) Develop procedures to isolate certain branches of the main steamlines (4.23.7.2).

(10) Provide Technical Specifications for reactor protection systems channels, including channel testing, checking, and calibration (4.26.1).

(11) Provide Technical Specifications for containment spray actuation signal logic (4.26.2).

Category 3, Additional Engineering Evaluation

It is the staff's position that all engineering evaluations and corresponding schedules for modifications be submitted on the established schedules as documented in the appropriate report sections and as summarized in Table 4.1.

(1) Improve control room ventilation system (4.1.3).

(2) Analyze structure roofs for probable maximum precipitation loading (4.2 and 4.6.2).

(3) Demonstrate by inspection or analysis adequate quality standards (4.4).

(4) Perform cost/benefit analysis to determine design windspeed and modifications including demonstration of protection for safe shutdown path and appropriate consideration of load combinations (4.5. 4.8, and 4.12.1).

(5) Demonstrate that safety-related structures remain functional for short-term hydrostatic loads at plant grade and resist flotation (4.6.1).

(6) Complete pipe break systems analysis inside containment, including fracture mechanics and review of cable routing (4.9 and 4.18).

(7) Complete analysis of pipe breaks outside containment (4.10 and 4.18).

(8) Complete seismic reevaluation program (4.11).

(9) Evaluate load combinations for reactor containment (4.12.2).

(10) Evaluate the merits of the recommended emergency core cooling system modifications (4.25.4, 4.32.2, and 4.32.5).

(11) Assess adequacy of transformer settings on the basis of the results of the voltage monitoring program (4.29.2).

(12) Analyze reliability of salt water cooling system (4.32.7).

(13) Analyze steam generator overfill event for possible corrective measures (4.35).

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TOPIC SAFETY EVALUATION REPORTS

Copies of this report and the associated safety evaluation reports for the 89 topics listed in Appendix E are available for public inspection at the NRC Public Document Room, 1717 H Street, N.W., Washington, D.C. 20555 and at the Main Library, University of California at Irvine, Irvine, California 92713. Copies of this report are also available for purchase from sources indicated on the inside front cover.

The review of the 89 topics was performed by the NRC staff and contractors listed in Appendix G. The members of the Integrated Assessment Team performing the integrated assessment of the 36 topics that did not meet current criteria are as follows:

E. McKenna--Project Manager, Integrated Assessment, San Onofre Unit 1
W. Paulson--Sr. Project Manager, San Onofre Unit 1
M. Rubin--Risk Assessment Analyst
A. D'Angelo--Resident Inspector, San Onofre Unit 1

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U.S. Nuclear Regulatory Commission
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INTEGRATED PLANT SAFETY ASSESSMENT
SYSTEMATIC EVALUATION PROGRAM
SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 1

1 INTRODUCTION

1.1 Background

In the late 1960s and early 1970s, the U. S. Atomic Energy Commission's (now Nuclear Regulatory Commission) scope of review of proposed power reactor designs was evolving and somewhat less defined than it is today. The requirements for acceptability evolved as new facilities were reviewed. In 1967, the Commission published for comment and interim use proposed General Design Criteria for Nuclear Power Plants (GDC) that established minimum requirements for the principal design standards. The GDC were formally adopted, though somewhat modified, in 1971, and have been used as guidance in reviewing new plant applications since then. Safety guides issued in 1970 became part of the Regulatory Guide Series in 1972. These guides describe methods acceptable to the staff for implementing specific portions of the regulations, including certain GDC, and formalize staff techniques for performing a facility review. In 1972, the Commission distributed for information and comment a proposed "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," now Regulatory Guide 1.70. It provided a standard format for these reports and identified the principal information needed by the staff for its review. The Standard Review Plan (SRP, NUREG-75/087) was published in December 1975 and updated in July 1981 (NUREG-0800) to provide further guidance for improving the quality and uniformity of staff reviews, to enhance communication and understanding of the review process by interested members of the public and nuclear power industry, and to stabilize the licensing process. For the most part, the detailed acceptance criteria prescribed in the SRP are not new; rather they are methods of review that, in many cases, were not previously published in any regulatory document.

Because of the evolutionary nature of the licensing requirements discussed above and the developments in technology over the years, operating nuclear power plants embody a broad spectrum of design features and requirements depending on when the plant was constructed, who was the manufacturer, and when the plant was licensed for operation. The amount of documentation that defines these safety-design characteristics also has changed with the age of the plant--the older the plant, the less documentation and potentially the greater the difference from current licensing criteria.

Although the earlier safety evaluations of operating facilities did not address many of the topics discussed in current safety evaluations, all operating facilities have been reviewed more recently against a substantial number of major safety issues that have evolved since the operating license was issued. Conclusions of overall adequacy with respect to these major issues (e.g., emergency core cooling system, fuel design, and pressure vessel design) are a matter of record. On the other hand, a number of other issues (e.g., seismic considerations, tornado and turbine missiles, flood protection, pipe break effects inside containment, and pipe whip) have not been reviewed against today's acceptance criteria for many operating plants, and documentation for them is incomplete.

1.2 Systematic Evaluation Program Objectives

The Systematic Evaluation Program (SEP) was initiated by the U. S. Nuclear Regulatory Commission (NRC) in 1977 to review the designs of older operating nuclear power plants in order to reconfirm and document their safety. The review provides (1) an assessment of the significance of differences between current technical positions on safety issues and those that existed when a particular plant was licensed, (2) a basis for deciding how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety.

The original SEP objectives were:

(1) The program should establish documentation that shows how the criteria for each operating plant reviewed compare with current criteria on significant safety issues, and should provide a rationale for acceptable departures from these criteria.

(2) The program should provide the capability to make integrated and balanced decisions with respect to any required backfitting.

(3) The program should be structured for early identification and resolution of any significant deficiencies.

(4) The program should assess the safety adequacy of the design and operation of currently licensed nuclear power plants.

(5) The program should use available resources efficiently and minimize requirements for additional resources by NRC or industry.

The program objectives were later interpreted to ensure that the SEP also provides safety assessments adequate for conversion of provisional operating licenses (POLs) to full-term operating licenses (FTOLs). The final version of the integrated plant safety assessment report and a POL conversion safety evaluation report that will address the status of all applicable generic activities (TMI and USI), including those that formed the basis for deletion of specific SEP topics, will form a part of the basis for the Commission's consideration of the license conversion.

Many of the plants selected for review were licensed before a comprehensive set of licensing criteria had been developed. They include five of the oldest nuclear reactor plants and seven plants under NRC review for the conversion of POLs to FTOLs. The plants to be considered under the original Phase II program were

(1) Yankee (FTOL PWR)
(2) Haddam Neck (FTOL PWR)
(3) Millstone 1 (POL BWR)

(4) Oyster Creek (POL BWR)
(5) Ginna (POL PWR) (FTOL conversion issued on December 10, 1984)
(6) LaCrosse (POL BWR)
(7) Big Rock Point (FTOL BWR)
(8) Palisades (POL PWR)
(9) Dresden 1 (FTOL BWR)
(10) Dresden 2 (POL BWR)
(11) San Onofre (POL PWR)

In a press release dated August 31, 1984 (referenced in an NRC Daily Highlight issued on September 4, 1984), the Commonwealth Edison Company, licensee for Dresden Unit 1, announced that Dresden Unit 1 was being retired. Since the licensee was not planning to restart this plant, the NRC cancelled the SEP review of Dresden Unit 1. Therefore, the total number of plants being reviewed in Phase II is 10.

1.3 Description of Plant

San Onofre Nuclear Generating Station, Unit 1, located in San Diego County near San Clemente, California, is a pressurized-water reactor designed by the Westinghouse Electric Company. The licensees are Southern California Edison Company and San Diego Gas and Electric Company. The architect/engineer is Bechtel Power Corporation.

Two other pressurized-water reactors (San Onofre Units 2 and 3) are located on the site adjacent to Unit 1. The San Onofre site is situated on the Pacific Ocean (both Interstate 5 and the Atchinson, Topeka and Santa Fe Railroad run alongside the site).

Southern California Edison, hereinafter referred to as the licensee, filed the application for a construction permit on February 1, 1963. The construction permit was issued on March 2, 1964. The initial submittal of the Final Safety Analysis Report was filed on November 12, 1965 and the initial provisional operating license was issued on March 27, 1967. The licensed thermal power rating is 1,347 megawatts-thermal (MWt).

The San Onofre Unit 1 primary coolant configuration consists of a reactor pressure vessel with three loops, each consisting of a hot-leg pipe delivering primary coolant to a U-tube (Series 27) steam generator with a reactor coolant pump in the cold-leg return. The pressurizer is connected to loop B by the surge line.

The secondary system consists of the shell side of the steam generators, the steam piping to the turbine/generator, the condenser, and the condensate and feedwater piping and pumps returning feedwater to the shell side of the steam generator. Saturated steam is supplied to the turbine from the steam generators through a common horseshoe header which exits containment in two lines and then passes through stop and governor valves. The steam flows through a high-pressure turbine and four moisture separator-reheaters to the two low-pressure turbines that exhaust to the main condenser. Turbine control is provided by an electrohydraulic control.

The main feedwater system consists of two electric-driven feedwater pumps that receive suction from the condensate-pump discharge through the low-pressure

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heaters. The electric condensate pumps take suction off the main condenser hotwell. The feedwater-pump flow is directed through the high pressure heaters, through the regulating valves, and to the steam generators.

Reactor containment (1,210,000-ft^3 net free volume) is provided by a 140-ft-diameter sphere which extends 40 ft below grade. It is supported by a concrete cradle between the steel shell and the soil. A concrete structure inside the sphere provides support and shielding for the equipment. A double-doored personnel lock, a double-sealed equipment door, and an emergency escape hatch supply access to the containment. During 1976, a sphere enclosure building was constructed which surrounds the containment and is a reinforced concrete structure with a 3-ft-thick cylindrical wall and an arched composite roof consisting of sloping steel beams and an 18-in. concrete slab. Other plant improvements made at that time included a new onsite emergency power system and diesel generator building and associated modifications to the emergency core cooling system (ECCS).

1.4 Summary of Operating History and Experience

San Onofre Nuclear Generating Station, Unit 1, received its provisional operating license on March 27, 1967, achieved initial criticality on June 14, 1967, and began commercial operation on January 1, 1968. The reactor has a licensed thermal power rating of 1,347 MWt and a design electric rating of 436 megawatts-electrical (MWe).

1.4.1 Summary of Oak Ridge National Laboratory Report (March 27, 1967, through December 31, 1981)

Presented below is a summary of the operating history of San Onofre Unit 1 from March 27, 1967, through December 31, 1981. Appendix F contains the full details of this history.

1.4.1.1 Introduction

Reactor availability at San Onofre Unit 1 for the period 1967 through 1981 was 68.3%. Reactor availability was above 70% except for 1968, 1973, 1977, 1980, and 1981. In these years the unit experienced extended shutdowns. In 1968, the plant was shut down for 6 months because of a cable fire. A turbine blade failure in 1973 required a 2-1/2-month shutdown for repair. Reactor coolant pump and steam generator tube inspections, along with steam generator tube plugging, required a 1-month shutdown in 1977. Steam generator tube repair also caused an 11-month shutdown for repair beginning in July 1980, resulting in the relatively low availability achieved in 1980 and 1981.

The operating history review focused on data evaluation that was divided into two segments: (1) evaluation of forced shutdowns and power reductions and (2) evaluation of reportable events. Design-basis events (DBEs), which are defined in the Standard Review Plan (NUREG-0800), are failures that initiate system transients and challenge engineered safety features. In the forced shutdown and power reduction segment, the review identified DBEs and recurring events that indicate a potential operating concern. In the reportable event segment, which included environmental events and radiological release events, the review identified significant events and recurring events that indicate a potential operating concern. Significant events were either DBEs or events with a loss of engineered safety function.

1.4.1.2 Forced Shutdowns and Power Reductions

Of the 154 forced shutdowns and power reductions at San Onofre Unit 1 between 1967 and 1981, 27 were identified as DBEs of one of the following types:

(1) control rod maloperation (12)
(2) turbine trip (5)
(3) increase in feedwater flow (4)
(4) loss of external electrical load (4)
(5) loss of normal feedwater flow (1)
(6) reactor coolant pump trip (1)

Of these 27 events, 21 resulted from equipment failure, 5 from personnel errors, and 1 from an offsite power disturbance.

San Onofre Unit 1 has experienced an average of less than two DBEs per year with no discernible trend in the frequency with which DBEs have occurred. Control rod maloperation caused 12 of the 27 DBEs. All 12 involved dropped control rods and occurred between 1967 and 1977, with 4 events occurring in 1968 and 3 in 1977. The problem has not occurred since 1977.

1.4.1.3 Reportable Events

In the reportable event segment of the operating review of San Onofre Unit 1, 327 events were examined. From 1967 through 1974, an average of 17 events per year was recorded; from 1975 to 1981, the average was 27 events. The increasing number of events reported can be attributed in part to events concerning steam generator and condenser tube leakage.

The cause of the majority of the reportable events at San Onofre Unit 1 was inherent equipment failure (60%). Human error (including administrative, design, fabrication, installation, maintenance, and operator error) caused another 35% of the events. Other causes including weather, minor earthquakes, and offsite brush fires accounted for the remaining 5% of the events.

Of the 237 events reviewed, 23 were identified as significant and are categorized as

(1) loss of safety injection system function (3)
(2) loss of salt water cooling flow (1)
(3) loss of offsite power (5)
(4) loss of emergency ac power supply (3)
(5) feedwater supply transients (3)
(6) cable tray fires (2)
(7) loss of boric acid injection path (2)
(8) failure of instrumentation channels caused by flooding (2)
(9) turbine overspeed (2)

The first two types of significant events are discussed in this summary.

Two potential losses of safety injection function and one failure to actuate safety injection on demand have occurred at San Onofre Unit 1. In 1967, 1 month before power operation, both safety injection recirculation pumps were declared inoperable. Moisture penetration of the motor windings caused both pumps to fail resistance testing. The openings to the windings were sealed to prevent recurrence.

In 1975, the licensee reported a potential single failure that would cause loss of at least a portion of the flow from both safety injection trains. Failure of either of the two safety injection pumps' discharge valves could allow safety injection flow from both pumps to be routed to the steam generator rather than to the reactor coolant system. Administrative controls were established to protect against such a failure, and subsequently extensive modifications corrected the problem.

On September 3, 1981, a voltage regulator failure caused erratic instrument readings leading to a manual reactor trip. In the transient following the trip, safety injection actuation occurred as a result of a decrease in reactor coolant system (RCS) pressure. However, operators discovered that both the safety injection valves had failed to open. Because the RCS pressure never dropped to the discharge pressure of the safety injection pumps, safety injection system flow would not have occurred even if the valves had opened. However, the valve failures affected both trains of safety injection. A design evaluation and further testing determined that the valves would not open against the design differential pressure. Design changes were evaluated and implemented to correct the problem. Augmented surveillance testing of these valves was also instituted.

On March 10, 1980, while operating at 100% power, San Onofre Unit 1 experienced a complete loss of flow from the salt water cooling system. The salt water cooling system is the ultimate heat sink for the component cooling water (CCW) system, which serves to cool certain safety-related equipment. The event involved a triple failure consisting of (1) shearing of the south salt water cooling pump shaft, (2) failure of the north salt water cooling pump discharge valve to open, and (3) failure of the auxiliary salt water cooling pump air priming system. As a result, the plant was totally without salt water cooling flow for 10 minutes, at which time an operator cross-connected the screen wash pumps to provide salt water flow to a CCW heat exchanger. This limited the CCW temperature rise from 66°F to 82°F in the 10 minutes and brought the equilibrium temperature down to 70°F. The screen wash pumps are not classified as safety-related equipment.

At 41 minutes into the event, the auxiliary salt water cooling pump was restored to service and flow through it to an inservice CCW heat exchanger began 17 minutes later. Throughout the event, the unit remained at or near full power. A power reduction was initiated at first, but then stopped with only a 3-MW power decrease. The NRC cited the plant for two Technical Specification violations in this event.

Although not in the original time frame for this examination of operating experience, three more events involving the salt water cooling system occurred in 1982 and are discussed here. On May 13, 1982, a complete loss of salt water cooling system flow occurred during maintenance. During this event, the unit was in cold shutdown. The event was caused by flooding of the intake structure as a result of inadequate maintenance procedures. On August 13, 1982, flow from the operable north salt water cooling pump was diverted through the idle south pump. This occurred as a result of unexpected opening of the south pump's discharge valve. An operator immediately closed the valve, and no observable reactor coolant system temperature increase occurred. On August 19, 1982, with the south salt water cooling pump still out of service, the north pump had to be removed from service because of a smoking motor bearing. Necessary flow to the CCW heat exchangers was maintained by the auxiliary salt water cooling pump. These events are discussed further in Section 4.32.

1.4.1.4 Recurring Events

In addition to individual events considered significant, there are five areas in which problems have recurred at San Onofre Unit 1 over portions of the operating history. The problem areas were

(1) inverter failures and losses of vital bus power
(2) steam generator leaks
(3) dilution of primary coolant
(4) tsunami gate closure
(5) erroneous control rod indications

There have been 21 occurrences of momentary loss of vital power, causing 5 shutdowns and 9 power reductions. These events occurred from 1969 to 1979, with all but one of the vital power interruptions due to inverter failures.

After the first 5 years of operation, steam generator tube leakage became a problem. Beginning in 1972, steam generator tube leaks began recurring, causing 9 forced shutdowns and 17 reportable events. Steam generator tube leakage problems and required repairs were the reason for the 11-month shutdown that began in July 1980.

On four occasions, dilution of the primary coolant system resulted in reduced boron concentration. The first of these events was due to secondary-to-primary system leakage during tube plugging. Another secondary-to-primary leakage that resulted in boron dilution was caused by a leaking block valve in the feedwater system. The remaining two dilution events occurred because water was added to the primary system during decontamination of equipment.

On three occasions, San Onofre Unit 1 has experienced inadvertent closure of the tsunami gate, the salt water intake stop gate. These events occurred in 1967, 1968, and 1969 and were caused by a shorted limit switch, rupture of the accumulator reservoir tank, and failure of the gate's annular bolts, respectively.

1.4.2 Operating Experience, January 1982 Through August 1986

On February 27, 1982, San Onofre Unit 1 was shut down for a scheduled 14-week outage so that the steam generators could be inspected and seismic modifications to the turbine deck could be made. As part of the seismic reevaluation of San Onofre Unit 1 under SEP, the staff concluded in a meeting on May 20, 1982, that because of the high stresses calculated in the seismic reevaluation, the licensee needed to provide information that demonstrates that the facility meets its licensed design basis before the plant would be permitted to restart.

In letters dated June 15 and 24, 1982, the licensee proposed a program to upgrade the plant to current seismic design criteria rather than expend resources to evaluate the design against the original design criteria. That commitment was confirmed by an order issued on August 11, 1982, which required that the licensee maintain Unit 1 in a shutdown condition until the modifications were complete and NRC approval was obtained for restart. The plant was maintained in a shutdown condition until November 21, 1984, when the NRC issued authorization for resumption of power operation. The seismic design issue is discussed further in Section 4.11.

On November 21, 1985, San Onofre Unit 1 experienced a loss of power and waterhammer event. The findings and conclusions of an NRC Incident Investigation Team's review of the event are documented in NUREG-1190. Corrective actions arising from that incident are being implemented independently of the SEP. The plant resumed operation following this event in July 1986.

1.4.3 Regulatory Performance, October 1, 1984, Through May 31, 1986

An NRC report, issued on August 7, 1986, presented the findings of NRC's Systematic Assessment of Licensee Performance (SALP) of Southern California Edison Company, conducted in accordance with NRC Manual Chapter 0516. That review included an assessment of the licensee's performance with the objective of improving regulatory programs and was based on activities during the period from October 1, 1984, through May 31, 1986. The SALP board concluded that the licensee's operational and regulatory performance was acceptable and directed toward safe operation.

The SALP board's conclusions for each of the functional areas were categorized as follows:

Category 1

Reduced NRC attention may be appropriate. The attention and involvement of the licensee's management are aggressive and oriented toward nuclear safety; the licensee's resources are ample and effectively used so that a high level of performance with respect to operational safety or construction is being achieved.

Category 2

NRC attention should be maintained at normal levels. The attention and involvement of the licensee's management are evident and are directed toward nuclear safety; the licensee's resources are adequate and are reasonably effective so that satisfactory performance with respect to operational safety or construction is being achieved.

Category 3

Both NRC and licensee attention should be increased. The attention and involvement of the licensee's management are acceptable and are directed toward nuclear safety, but weaknesses are evident; the licensee's resources appear strained or not effectively used so that minimally satisfactory performance with respect to operational safety and construction is being achieved.

The SALP report addressed licensee performance with respect to all three San Onofre units. The overall ratings for the functional areas at the San Onofre site were as follows:

Category 1:

(1) radiological controls
(2) fire protection
(3) outages

Category 2:

(1) maintenance
(2) emergency preparedness
(3) surveillance
(4) licensing activities
(5) plant operations
(6) security and safeguards
(7) training
(8) quality programs and administrative controls

Category 3:

None

2 REVIEW METHOD

2.1 Overview

The Systematic Evaluation Program (SEP) review procedure represents a departure from the typical NRC staff reviews conducted to support the granting of a contruction permit or operating license for a new facility or a license amendment for an operating facility. A typical licensing review starts with the submittal by the utility of a safety analysis report (SAR) that describes the design of the proposed plant. The staff reviews the SAR on the basis of the Standard Review Plan (SRP), Regulatory Guides, and Branch Technical Positions (found in the SRP) that constitute current licensing criteria. The guidelines in the SRP represent acceptable means of complying with licensing regulations specified in Title 10 of the Code of Federal Regulations (10 CFR).

The SEP was initiated by the NRC, and not by the licensee as part of an application for a license or request for a license amendment. The SEP procedure involves several phases of data gathering and evaluation so that an integrated assessment of the overall plant safety can be made. The various phases and their interrelationships are described below.

2.2 Selection of Topic List

A list of significant safety topics was derived from existing safety issues during Phase I of the program. More than 800 items were considered in the development of the original list; however, a number of these were found to be duplicative in nature or were deleted for other reasons. Categories of topics that were deleted for other reasons are (1) those not normally included in the review of light-water reactors, (2) those related either to research-and-development programs or to the development of analytical evaluation models and methodology, and (3) those that are reviewed on a periodic basis in accordance with current criteria (e.g., fuel performance). The topics retained numbered 137; these were arranged in groups corresponding to the organization of the SRP. A "definition" was prepared for each topic to ensure a common understanding. This definition plus a statement of the safety objective for the review and the status of the review at that time is contained in Appendix A for ease of reference.

During the course of this review, the number of topics that applied to all plants was reduced further because some topics were being reviewed generically under either the Unresolved Safety Issues (USIs) program or the Three Mile Island (TMI) NRC Action Plan (NUREG-0660); also, duplicates found within the SEP topics were deleted. Appendix B shows these topics along with the corresponding USI, TMI task, or SEP topic referenced. The basis for deletion appears in Appendix A under the individual topics.

Plant-specific deletions other than those common to all SEP plants were made to account for nonapplicability of particular topics to San Onofre Unit 1. The plant-specific topics that were removed for San Onofre Unit 1 and the basis for deletion are shown in Appendix C.

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For San Onofre Unit 1, this deletion process resulted in 89 topics from the original topic list that formed the SEP review for San Onofre. The final list of 89 topics that were reviewed appears in Section 3.1.

The milestones in the review of the SEP and the San Onofre Unit 1 plant are shown in Table 2.1.

2.3 Topic Evaluation Procedures

Each SEP topic in Section 3.1 was reviewed to determine whether the corresponding plant design was consistent with current licensing criteria such as regulations, guides, and SRP review criteria, or the equivalent of such criteria. Safety evaluation reports (SERs) for all 89 topics were issued to document the comparison with current licensing criteria and to identify potential areas for plant modifications or changes to plant Technical Specifications or procedures. References for letters regarding the individual topic SERs are contained in Appendix E. These documents describe the detailed evaluations where conclusions are summarized in this report.

Topics were evaluated by one of two methods:

(1) The NRC staff reviewed and formally issued an SER to the licensee. This SER was termed a draft because it was only one input element to the evaluation. The purpose of the draft SER was to verify the factual accuracy of the described facility and to allow the licensee to identify possible alternate approaches to meeting the current licensing criteria. After a review of the licensee's comments on the draft SER, factual changes were incorporated as needed, proposed alternatives were reviewed, and the SER was issued in final form.

(2) The licensee submitted a safety analysis report, and the staff issued a final SER based on a review of this submittal.

After completion of the topic evaluation, the disposition of each topic was grouped according to one of the following results:

(1) The plant is consistent with current licensing criteria and the topic review is considered complete. If the plant does not meet current licensing criteria, but the present design is equivalent to current criteria, the topic is also considered complete. A justification for this conclusion is provided in the topic SER. The topics in this category are identified in Section 3.1 of this report by an asterisk.

(2) The plant is not consistent with current licensing criteria, but the licensee has implemented design or procedural changes that the staff finds acceptable. Although the licensee committed to certain design or procedural changes during the course of the topic reviews for San Onofre Unit 1, and in some cases these measures were implemented, none of the topics were completely resolved by these commitments.

(3) The plant is not consistent with current licensing criteria, and the differences from these criteria are to be evaluated as potential candidates for modifications. If the staff determines the difference is of immediate

safety significance, action is taken to resolve the issue promptly. If the difference is not of immediate safety significance, the resolution is deferred to the integrated plant safety assessment to obtain maximum benefit from coordinated and integrated backfitting decisions. The SEP evaluation of all 89 topics led to the conclusion that 36 topics were not consistent with current licensing criteria. All of these topics were considered in the integrated safety assessment and appear in Section 4.

The only one of the 36 topics found not to be consistent with current licensing criteria and to be of immediate safety significance requiring prompt action, is the capability of the plant to withstand a seismic event. As part of the seismic reevaluation of San Onofre Unit 1 conducted under SEP, the staff concluded that because of high calculated stresses, the plant would not be permitted to restart from its then current outage in 1982, until the licensee could demonstrate that the plant meets its licensed design basis. The licensee proposed a program to upgrade the plant to current seismic design criteria. As discussed later, the staff has determined, based on its review of modifications to the facility and analyses submitted by the licensee, that continued operation of Unit 1 is acceptable pending completion of the seismic upgrading program. Further details of this prompt action are provided in Sections 1.4.2 and 4.11.

2.4 Integrated Plant Safety Assessment

The objective of the integrated plant safety assessment is to make balanced and integrated decisions on the application of current licensing criteria to SEP facilities. Factors considered important in reaching those decisions include safety significance, radiation exposure to workers, and, to a lesser extent, implementation impact and schedule.

A meeting was held with the licensee to discuss these factors as they related to the differences identified during the SEP review between actual facility design and current licensing criteria and to obtain the licensee's views on safety significance and possible corrective actions.

These factors were considered in reaching a decision on plant modifications and are discussed in Section 4 for each identified difference between actual facility design and current licensing criteria. Because these factors sometimes rely on judgment, risk assessment techniques were used to the extent possible to supplement the staff's judgments concerning safety significance. The probabilistic risk assessment (PRA) performed by Science Applications, Inc., along with comments by the staff, appears in Appendix D. For reasons given in Appendix D, only certain topics could be readily analyzed by a PRA. Of the total number of topics considered in the integrated assessment, 17 were evaluated using PRA techniques.

The staff's findings presented in the draft integrated assessment were discussed with the Advisory Committee on Reactor Safeguards in August 1985. The Committee's comments and the staff's response to those comments appear in Appendix H.

The draft integrated assessment was issued in April 1985. To provide an additional level of perspective to the staff's findings, the draft integrated assessment was reviewed by three independent consultants. The consultants' comments and the staff's response to the comments appear in Appendix I.

Table 2.1 Topic list selection and resolution

ORIGINAL PHASE I TOPIC LIST
800

Many of these topics were deleted because they were duplicative in nature, were not normally included in the review of light-water reactors, were related to research-and-development programs, or were reviewed on a periodic basis in accordance with current criteria.

FINAL LIST OF PHASE I TOPICS REVIEWED DURING PHASE II
137 (see Appendix A)

Of the 137 topics, 24 were deleted because they were being reviewed generically under either the Unresolved Safety Issues (USIs) program or the Three Mile Island (TMI) NRC Action Plan (see Appendix B).

REMAINING TOPICS AFTER DELETION OF USIs AND TMI-RELATED TOPICS
113

Of the remaining 113 topics, 24 were deleted because the topics did not apply to San Onofre Unit 1 (see Appendix C).

FINAL NUMBER OF TOPICS REVIEWED FOR SAN ONOFRE UNIT 1
89 (see Section 3.1 and Appendix E)

TOPICS THAT MET CURRENT CRITERIA OR WERE
ACCEPTABLE ON ANOTHER DEFINED BASIS
53 (see Section 3.1)

TOPICS THAT MET CURRENT CRITERIA OR WERE ACCEPTABLE ON ANOTHER
DEFINED BASIS AFTER MODIFICATIONS MADE DURING TOPIC REVIEW
0

TOPICS CONSIDERED FOR BACKFIT IN THE INTEGRATED ASSESSMENT
36 (see Table 4.1 and Sections 4.1-4.36)

3 TOPIC EVALUATION SUMMARY

3.1 Final San Onofre Unit 1-Specific List of Topics Reviewed

Listed below are the 89 topics that were reviewed for San Onofre Unit 1. The topics with asterisks are those for which the plant meets current criteria or was acceptable on anotner defined basis.

TOPIC	TITLE
II-1.A*	Exclusion Area Authority and Control
II-1.B*	Population Distribution
II-1.C	Potential Hazards or Changes in Potential Hazards Due to Transportation, Institutional, Industrial, and Military Facilities
II-2.A*	Severe Weather Phenomena
II-2.C*	Atmospheric Transport and Diffusion Characteristics for Accident Analysis
II-3.A*	Hydrologic Description
II-3.B	Flooding Potential and Protection Requirements
II-3.B.1*	Capability of Operating Plant To Cope With Design-Basis Flooding Conditions
II-3.C*	Safety-Related Water Supply (Ultimate Heat Sink (UHS))
II-4*	Geology and Seismology
II-4.A*	Tectonic Province
II-4.B*	Proximity of Capable Tectonic Structures in Plant Vicinity
II-4.C*	Historical Seismicity Within 200 Miles of Plant
II-4.D*	Stability of Slopes
II-4.F	Settlement of Foundations and Buried Equipment
III-1	Classification of Structures, Components, and Systems (Seismic and Quality)
III-2	Wind and Tornado Loadings
III-3.A	Effects of High Water Level on Structures

TOPIC	TITLE
III-3.C	Inservice Inspection of Water Control Structures
III-4.A	Tornado Missiles
III-4.B*	Turbine Missiles
III-4.C*	Internally Generated Missiles
III-4.D*	Site-Proximity Missiles (Including Aircraft)
III-5.A	Effects of Pipe Break on Structures, Systems, and Components Inside Containment
III-5.B	Pipe Break Outside Containment
III-6	Seismic Design Considerations
III-7.B	Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria
III-7.D	Containment Structural Integrity Tests
III-8.A	Loose-Parts Monitoring and Core Barrel Vibration Monitoring
III-8.C*	Irradiation Damage, Use of Sensitized Stainless Steel, and Fatigue Resistance
III-10.A	Thermal-Overload Protection for Motors of Motor-Operated Valves
III-10.B	Pump Flywheel Integrity
IV-1.A*	Operation With Less Than All Loops In Service
IV-2	Reactivity Control Systems Including Functional Design and Protection Against Single Failures
V-5	Reactor Coolant Pressure Boundary (RCPB) Leakage Detection
V-6*	Reactor Vessel Integrity
V-7*	Reactor Coolant Pump Overspeed
V-10.A	Residual Heat Removal System Heat Exchanger Tube Failures
V-10.B*	Residual Heat Removal System Reliability
V-11.A	Requirements for Isolation of High- and Low-Pressure Systems
V-11.B	Residual Heat Removal System Interlock Requirements

TOPIC	TITLE
VI-1	Organic Materials and Postaccident Chemistry
VI-2.D*	Mass and Energy Release for Postulated Pipe Break Inside Containment
VI-3*	Containment Pressure and Heat Removal Capability
VI-4	Containment Isolation System
VI-6*	Containment Leak Testing
VI-7.A.1*	Emergency Core Cooling System Reevaluation To Account for Increased Reactor Vessel Upper-Head Temperature
VI-7.A.3*	Emergency Core Cooling System Actuation System
VI-7.B	Engineered Safety Features Switchover From Injection to Recirculation Mode (Automatic Emergency Core Cooling System Realignment)
VI-7.C*	Emergency Core Cooling System (ECCS) Single-Failure Criterion and Requirements for Locking Out Power to Valves, Including Independence of Interlocks on ECCS Valves
VI-7.C.1*	Appendix K--Electrical Instrumentation and Control Re-Reviews
VI-7.C.2	Failure Mode Analysis (Emergency Core Cooling System)
VI-7.D*	Long-Term Cooling Passive Failures (e.g., Flooding of Redundant Components)
VI-10.A	Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing
VI-10.B*	Shared Engineered Safety Features, Onsite Emergency Power, and Service Systems for Multiple Unit Facilities
VII-1.A	Isolation of Reactor Protection System From Nonsafety Systems, Including Qualification of Isolation Devices
VII-1.B*	Trip Uncertainty and Setpoint Analysis Review of Operating Data Base
VII-2*	Engineered Safety Features System Control Logic and Design
VII-3	Systems Required for Safe Shutdown
VII-6*	Frequency Decay
VIII-1.A	Potential Equipment Failures Associated With Degraded Grid Voltage

TOPIC	TITLE
VIII-2*	Onsite Emergency Power Systems (Diesel Generator)
VIII-3.A*	Station Battery Capacity Test Requirements
VIII-3.B	DC Power System Bus Voltage Monitoring and Annunciation
VIII-4	Electrical Penetrations of Reactor Containment
IX-1*	Fuel Storage
IX-3	Station Service and Cooling Water Systems
IX-4*	Boron Addition System (PWR)
IX-5	Ventilation Systems
IX-6	Fire Protection
XIII-2*	Safeguards/Industrial Security
XV-1	Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve
XV-2	Spectrum of Steam System Piping Failures Inside and Outside Containment (PWR)
XV-3*	Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulator Failure (Closed)
XV-4*	Loss of Nonemergency AC Power to the Station Auxiliaries
XV-5*	Loss of Normal Feedwater Flow
XV-6*	Feedwater System Pipe Breaks Inside and Outside Containment (PWR)
XV-7*	Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break
XV-8*	Control Rod Misoperation (System Malfunction or Operator Error)
XV-9*	Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate
XV-10*	Chemical and Volume Control System Malfunction That Results in a Decrease in Boron Concentration in the Reactor Coolant (PWR)
XV-12*	Spectrum of Rod Ejection Accidents (PWR)

TOPIC	TITLE
XV-14*	Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory
XV-15*	Inadvertent Opening of a PWR Pressurizer Safety/Relief Valve or a BWR Safety/Relief Valve
XV-16*	Radiological Consequences of Failure of Small Line Carrying Primary Coolant Outside Containment
XV-17*	Radiological Consequences of Steam Generator Tube Failure (PWR)
XV-19*	Loss-of-Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary
XV-20*	Radiological Consequences of Fuel-Damaging Accidents (Inside and Outside Containment)
XVII*	Operational Quality Assurance Program[1]

3.2 Topics for Which Plant Design Meets Current Criteria or Was Acceptable on Another Defined Basis

As listed in Section 3.1.

3.3 Topics for Which Plant Design Meets Current Criteria or Equivalent Based on Modifications Implemented by the Licensee

As described in Section 2.3; although the licensee committed to certain design and procedural changes during the course of the topic reviews, none of the topics were completely resolved by these commitments.

As a result of SEP reviews, TMI requirements, or generic issues, the following modifications have been made to San Onofre Unit 1. Additional modifications or analyses, as identified in Section 4 of this report, will be required to resolve the open items.

(1) installation of grade beams under 480-V room slab and under auxiliary feedwater pumps to span backfill soils (Topic II-4.F, Section 4.3)

(2) seismic upgrades to safety-related structures and to equipment, piping, and supports for 0.67g modified Housner spectrum earthquake (Topic III-6, Section 4.11)

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[1] The Operational Quality Assurance Program was reviewed according to the criteria specified for operating reactors in 1974 (see Appendix A). NRC is currently evaluating all aspects of Nuclear Power Plant Quality Assurance Programs. Additional review of this issue will be performed outside the context of the SEP.

(3) surveillance and operability requirements for component cooling water system radiation monitor (Topic V-10.A, Section 4.19.1)

(4) independent verification of correct valve position of motor-operated valves in the safety injection system after testing (Topic V-11.A, Section 4.20.2)

(5) inspection and repairs of containment coatings (Topic VI-1, Section 4.22)

(6) Technical Specifications implemented to maintain purge valves locked closed when above the cold shutdown mode (Topic VI-4, Section 4.23.1.1)

(7) installation of new auxiliary feedwater storage tank, new parellel suction paths (Topic VII-3, Section 4.28.2)

(8) modification of transformer tap settings based on voltage distribution study (Topic VIII-1.A, Section 4.29)

(9) removal of tsunami gates (Topic IX-3, Section 4.32)

(10) installation of check valves in the saltwater cooling system discharge and removal of air operators from discharge isolation valves (Topic IX-3, Section 4.32.7)

(11) installation of non-safety-related ventilation systems in the switchgear rooms (Topic IX-5, Section 4.33.2)

4 INTEGRATED ASSESSMENT SUMMARY

Table 4.1 shows the list of topics considered in the integrated assessment, whether Technical Specification requirements or modifications are needed, and whether or not the licensee proposes to modify San Onofre Unit 1. A more detailed description of each topic with identified differences follows.

The differences from current licensing criteria identified in this section were derived from the safety evaluation reports referenced in Appendix E.

A limited probabilistic risk assessment (PRA) has been performed for 17 of the SEP topics with identified differences from current licensing criteria. This limited PRA is presented in Appendix D and is based on issue-specific models developed from PRAs for similar plants and global insights from all PRA experience. This risk perspective has been used to judge the importance of the identified differences in relation to accident sequences leading to core melt, with due consideration of the uncertainties in the PRA techniques. In addition, the licensee has performed an integrated assessment, submitted by letters dated January 19, February 24, March 30, and May 7, 1984, and has proposed corrective actions to resolve those issues considered significant. The completion schedules and revised commitments resulting from the review of the draft report were submitted in a letter dated October 4, 1985 as revised July 28, 1986.

The licensee's submittals have been evaluated by the staff and together with the limited PRA results have been used as input to this integrated plant safety assessment. Where the licensee's proposed corrective actions are consistent with or equivalent to current licensing criteria, they constitute the basis for the staff's acceptance. The remaining issues were evaluated using the process described in Section 2.4.

4.1 Topic II-1.C, Potential Hazards or Changes in Potential Hazards Due to Transportation, Institutional, Industrial, and Military Facilities

10 CFR 50, Appendix A, General Design Criterion (GDC) 4, as implemented by SRP Section 2.2, requires, in part, that structures, systems, and components important to safety be appropriately protected from dynamic effects that may result from events and conditions outside the nuclear power unit. Offsite hazards that have the potential for causing onsite accidents leading to the releases of significant quantities of radioactive fission products should have a sufficiently low probability of occurrence so that they are within the scope of the criterion of 10 CFR 100.10.

4.1.1 Overpressure From Explosions

At San Onofre Unit 1, the frequency of exceeding an overpressure on the site of 0.5 psi (capacity of reactor auxiliary building (RAB)) from explosions on the nearby railroad or highway is calculated to be 4.5×10^{-6} per year. SRP Section 2.2 defines design-basis events external to the station as those accidents for which a realistic estimate of the annual probability of exceeding 10 CFR 100 exposure guidelines is in excess of approximately 10^{-7} and for which a conservative estimate of the probability is in excess of approximately 10^{-6}. As stated in the staff's safety evaluation forwarded by letter dated May 3, 1983, the licensee's analysis includes sufficient conservatisms so that the risk is judged to be substantially lower than 4.5×10^{-6} per year. For instance, the calculated frequency is for RAB overpressure; it is not expected that exceeding the overpressure capability of the weakest structure will necessarily result in releases in excess of the 10 CFR 100 guidelines. Therefore, the staff concluded that modifications of plant structures are not warranted.

4.1.2 Frequency of Shipments

Highway shipments of munitions and flammable gases, such as liquid propane gas, are the predominant contributors to the overpressure hazard. Data were collected for the San Onofre Units 2/3 license review and were submitted for review for Unit 1 on November 12, 1981. Because of the sensitivity of the results of the analysis to the frequency of shipments, the staff concluded in the topic evaluation that the licensee should update these frequencies to ensure that the analysis assumptions remain applicable.

By letter dated October 31, 1983, the licensee noted that information on hazardous shipments past the site is required by the Unit 2/3 Technical Specifications to be collected and provided to the NRC every 3 years. This information was submitted on December 5, 1984. The licensee's report concluded that neither the frequency of shipment nor types of hazardous materials have changed significantly. The staff concludes that these licensee actions are sufficient to address this concern and considers this issue to be resolved.

4.1.3 Toxic Gases

The staff in its topic evaluation concluded that the probability of toxic gases, from transportation sources, being swept into the control room air vent in any 1-year period is approximately 5×10^{-6}. The staff has also noted that there is onsite storage of toxic materials. Currently, no automatic isolation of the control ventilation system is provided. Also, the existing system is a single-train design. Consequently, the staff recommended that the licensee perform an evaluation of the control room ventilation system, which would include a cost-benefit study of various system improvements to provide protection from both toxic gases and radioactivity (TMI Action Plan item III.D.3.4). By letter dated November 14, 1984a, revised September 19, 1985, the licensee submitted a study of various improvements to the control room ventilation system. A description of the modifications to be made to the control room ventilation system was submitted in a letter dated October 10, 1986a. Staff conclusions for this issue will be reported in a supplement to the final IPSAR.

4.2 Topic II-3.A, Hydrologic Description; Topic II-3.B, Flooding Potential and Protection Requirements; Topic II-3.B.1, Capability of Operating Plants To Cope With Design-Basis Flooding Conditions; and Topic II-3.C, Safety-Related Water Supply (Ultimate Heat Sink (UHS))

10 CFR 50 (GDC 2), as implemented by SRP Sections 2.4.2, 2.4.5, 2.4.10, and 2.4.11 and Regulatory Guides 1.59 and 1.27, requires, in part, that structures, systems, and components important to safety be designed to withstand the effects of natural phenomena such as flooding. The safety objective of these topics (II-3.A, II-3.B, II-3.B.1, and II-3.C), is to verify that adequate operating procedures and/or system design are provided to cope with the design-basis flood.

During the review of the hydrology-related topics, the staff has identified one issue for further evaluation. In the event of probable maximum precipitation (PMP), the fuel storage building and ventilation equipment building roofs would be subject to ponding, possibly resulting in loading in excess of the design basis for the roofs.

It is the staff position that the licensee should assess the capacity of the structures to withstand the load and, if necesary, provide corrective measures such as additional roof drainage (see Section 4.6.2).

The licensee's assessment of the roof capacity was submitted by letter dated April 26, 1985. The conclusions of the staff's review will be provided in a supplement to the final IPSAR.

4.3 Topic II-4.F, Settlement of Foundations and Buried Equipment

10 CFR 50 (GDC 2 and 44) and 10 CFR 100, Appendix A, as implemented by Regulatory Guide 1.132 and SRP Section 2.5.4, require, in part, that foundations and buried equipment important to safety be adequately designed to perform their intended functions in the event of settlement.

During excavations for seismic support modifications in 1982, it was found that the backfill soil beneath some safety-related structures and components was not as compacted as had been thought. The licensee determined the distribution of backfill soil and its relative compaction. Where safety-related equipment or structures were supported by the backfill, evaluation of the effect on seismic capacity was performed and in some instances, modifications were made, such as installation of grade beams to span the backfill soil. The licensee has concluded that with those modifications, there will be no adverse static or dynamic settlement problems. For some equipment, assessment of the need for foundation modifications is continuing.

By letter dated August 20, 1985, the staff issued a final safety evaluation on SEP Topic II-4.F, which concurred with the licensee's geotechnical assessment of the backfill conditions, of the possible settlement, and of the parameters to use for foundation analyses. The response of structures, systems, and components to seismic events, including consideration of existing soil conditions, is evaluated in Section 4.11. Therefore, this topic is considered complete.

4.4 Topic III-1, Classification of Structures, Components, and Systems (Seismic and Quality)

10 CFR 50 (GDC 1), as implemented by Regulatory Guide 1.26, requires, in part, that structures, systems, and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. The codes used for the design, fabrication, erection, and testing of the San Onofre Unit 1 plant were compared with current codes.

The development of the current edition of the American Society of Mechanical Engineers "Boiler and Pressure Vessel Code" (ASME Code) has been a process evolving from earlier ASME Code, American National Standards Institute, and other standards, and manufacturer's requirements. In general, the materials of construction used in earlier designs provide comparable levels of safety.

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The staff in its topic evaluation identified several systems and components for which the licensee was unable to provide information to justify a conclusion that the quality standards imposed during plant fabrication and construction meet the quality standards required for new facilities. The staff did not identify any inadequate components. However, because of the limited information on the components involved, the staff was unable to conclude that, for code and standard changes deemed important to safety, the San Onofre Unit 1 plant met the intent of current requirements. The information described below was requested in the topic SERs forwarded by letters dated June 25, 1982, and April 23, 1984.

It is the staff's position that the licensee should complete the evaluations described below. As an alternative, since much of the requested information may not exist, the licensee may evaluate the safety significance of the components and systems in question and show that they are either adequately monitored by a formal inspection program or are of no consequence on the basis of risk or safety function. The results of the evaluation should be incorporated into the Final Safety Analysis Report update, which must be submitted within 2 years after completion of the SEP review per the requirements of 10 CFR 50.71(e)(3)(ii). If the results of the licensee's evaluations indicate that facility modifications or inspection program changes are required, those actions should be reported to the staff.

The licensee has agreed to the staff's position.

4.4.1 Radiography Requirements

ASME Code, Section III, requires that Categories A, B, and C weld joints be radiographed. Furthermore, ASME Code, Section III, 1977 Edition, requires that weld joints for Class 1 and 2 piping, pumps, and valves be radiographed. Because information was not available during the topic review, the staff concluded that the licensee should verify that (1) the control rod drive housing, (2) Class 2 and 3 vessels for which Code Case 1273N was not invoked and having welded joint thicknesses less than 1½ in., and (3) Class 1 and 2 piping and valves designed only to American Standards Association (ASA) B31.1 have been radiographed or subsequently volumetrically inspected. If neither has been done, the licensee should perform a volumetric inspection.

4.4.2 Pressure Vessels

The licensee should demonstrate compliance with current fatigue analysis requirements for all Class 1 vessels.

4.4.3 Fracture Toughness

ASME Code, Section III, imposes minimum fracture toughness requirements on carbon steel components. For 55 of the 112 components reviewed, the information was not sufficient to complete this review. The licensee should perform an evaluation of those items that are not exempt from current fracture toughness requirements to determine if toughness of the material is sufficient to ensure component integrity and, if it is not, evaluate the consequences and demonstrate acceptability or replace the components.

4.4.4 Piping

The current Class 1 piping design requirements are given in ASME Code, Section III, NB-3600. Calculations similar to those presented in Examples 1 and 2 in Section 4.2, Appendix A, of TER C5257-433 (enclosure to the SER forwarded by letter dated June 25, 1982), applicable to San Onofre Unit 1 plant design parameters, should be performed on a sampling basis to assess the impact on the usage factor of gross discontinuities in Class 1 piping systems for a medium and large number of cyclic loads.

4.4.5 Valves

Current ASME Code, Section III, design requirements regarding body shapes and Service Level C stress limits for Class 1 valves and pressure-temperature ratings for Class 2 and 3 valves are different from those used when the plant was designed. Sufficient information was not available to assess the valves in the above-stated areas. The licensee should verify, on a sampling basis, that Class 1 valve stress limits meet current criteria for body shape and Service Level C conditions and that the pressure-temperature ratings of Class 2 and 3 valves are comparable to current standards. If current criteria are not met, the licensee should take appropriate corrective action (analysis or upgrading).

4.4.6 Pumps

The staff in the topic evaluation concluded that codes, code classes, editions, code cases, and design calculations should be provided for nine of the pumps in the San Onofre Unit 1 plant. Proof of compliance with current fatigue analysis requirements for current Class 1 pumps (the reactor coolant pumps) should be established. The licensee should evaluate the design standards used for the other pumps in relation to current design standards and determine whether adequate safety margins exist.

4.4.7 Storage Tanks

Compressive stress requirements for atmospheric storage tanks and tensile stress requirements for 0- to 15-psig storage tanks designed to ASME Code, Section VIII (1962), or American Petroleum Institute (API) 650, differ from those of Section III, Class 2 and 3, of the current ASME Code. Sufficient information was not available during the topic review to assess the significance of these changes for the tanks designed to earlier ASME Code editions or other code editions. The licensee should evaluate the margins of safety for (1) atmospheric storage tanks, which should be checked to determine if they meet current compressive stress requirements; (2) 0- to 15-psig tanks, which should be checked to determine if they meet current tensile allowable values for biaxial stress field conditions; and (3) tanks designed to API-650.

4.5 Topic III-2, Wind and Tornado Loadings

10 CFR 50 (GDC 2), as implemented by SRP Sections 3.3.1 and 3.3.2 and Regulatory Guides 1.76 and 1.117, requires, in part, that structures, systems, and components important to safety be designed to withstand the effects of natural phenomena

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such as wind and tornado loadings, including tornado pressure drop loading. Under Topic II-2.A, the staff in the topic evaluation recommended that a design straight windspeed of 75 miles per hour (mph) is acceptable for the site and that a tornado with a 10^{-7} per year frequency (a tornadic windspeed of 260 mph) and Δp of 1.5 psi should be the design basis.

The existing design and construction of some structures do not meet current licensing criteria regarding the ability of safety-related structures to resist such wind and tornado loads. The following were identified in the topic evaluation as items not meeting the prescribed loads.

(1) Ventilation stack--stack failure could affect safety-related structures and components.

(2) Components not enclosed in qualified structures--capacity of equipment has not been evaluated.

(3) Some safety-related structures including ventilation equipment, fuel storage, turbine, reactor auxiliary building (above grade), and control/administration building (other than control room)--failure could result in release to the environment or inability to shut down the plant.

(4) Gantry crane--failure could potentially affect safety-related equipment.

It was the staff's recommendation in the topic evaluation that the licensee should ensure that structures and equipment can withstand the design-basis straight and tornado wind loadings or the licensee should demonstrate that their failure will not prevent reaching a safe shutdown condition.

By letter dated September 17, 1984, the licensee submitted a Tornado Hazard Analysis Report. This report presented results of a site-specific analysis of tornado windspeed as a function of probability of occurrence. This report concluded that, at the 10^{-4} per year frequency level, tornado windspeed is 59 mph; at 10^{-5}, 103 mph; and at 10^{-7}, 183 mph. The crossover point of the tornadic wind with the straight wind hazard function is 75 mph.

A staff contractor (McDonald) had previously developed a tornado windspeed probability curve for the San Onofre Unit 1 site. At the upper 95% confidence limit curve, the values are 10^{-4}, 77 mph (straight wind); 10^{-5}, 113 mph; and 10^{-7}, 272 mph. An independent staff assessment of the wind/tornado hazard was also performed later. The findings of the second report are: at 10^{-4}, 80 mph (wind); at 10^{-5}, 135 mph; and at 10^{-7}, 270 mph. The crossover point is at approximately 85 mph (4×10^{-5}).

The next stage of the licensee's analysis for wind and tornado loadings is to perform an evaluation to demonstrate that there is adequate resistance for smaller tornado loadings and that the risk associated with larger loadings is acceptable. The evaluation, using the licensee's windspeed probability curves, will determine the scope of modifications necessary for safety-related structures and systems at each probability level/windspeed identified. On the basis of a cost/safety benefit evaluation, the licensee will recommend a design windspeed and conceptual modifications, and an implementation schedule will be developed. As discussed in a July 24, 1985, submittal, the licensee will provide

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a path for decay heat removal to ensure safe shutdown after a tornado event, including the consideration of both wind and missile effects. This evaluation was submitted in a letter dated October 10, 1986. The staff will judge the adequacy of the licensee's proposal based on the staff's wind hazard function described above.

4.6 Topic III-3.A, Effects of High Water Level on Structures

10 CFR 50 (GDC 2), as implemented by SRP Section 3.4 and Regulatory Guide 1.59, requires, in part, that plant structures be designed to withstand the effects of flooding. The safety objective of this topic is to ensure the function of safety-related structures with hydrostatic or hydrodynamic loading resulting from design-basis water levels when combined with other nonaccident loadings. The staff's review of this topic identified the following areas of concern.

4.6.1 Groundwater

The staff in the topic evaluation determined that a groundwater level at plant grade is appropriate for assessing the capacity of structures to withstand the short-term hydrostatic loads. It is the staff's position that the licensee should demonstrate that safety-related structures remain functional and resist flotation for short-term hydrostatic loads for a groundwater level at plant grade. As discussed in the licensee's letter of October 4, 1985, the licensee will evaluate the effects of groundwater at grade as a first cut in demonstrating structural capability. If the effects of water at grade are not acceptable, a more realistic assessment of extreme high groundwater levels will be made. The licensee submitted the results of this evaluation in a letter dated August 22, 1986.

The site grade elevation varies from 11 ft to 20 ft mean low level water (MLLW) datum. The staff in the topic evaluation concluded that for calculating load combinations, a groundwater level of 5 ft MLLW is appropriate. The licensee stated in the safety analysis for Topic III-3.A (October 20, 1983) that a 5-ft MLLW groundwater level was considered in the evaluation of load combinations on structures. The staff is evaluating the effects of load combinations in Topic III-7.B (see Section 4.12.1).

4.6.2 Roof Loadings

As discussed in Section 4.2, the fuel storage building and the ventilation building would be subject to ponding over low points of the roof. The licensee should either demonstrate that the roofs can withstand the load or propose corrective measures. The licensee submitted the results of this evaluation on April 26, 1985.

The staff review is continuing; the results will be reported in a supplement to the final IPSAR.

4.7 Topic III-3.C, Inservice Inspection of Water Control Structures

10 CFR (GDC 1, 2, and 44) and 10 CFR 100 (Appendix A), as implemented by SRP Sections 2.5.4 and 2.5.5 and Regulatory Guides 1.27, 1.28, 1.59, 1.127, and 1.132, require, in part, that water control structures built for use in conjunction with a nuclear power plant, whose failure could cause adverse radiological

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consequences, be inspected routinely. The inspection is intended for water control structures used for flood protection (on or off site) and emergency cooling water systems. The safety objective is to ensure that water control structures that are part of the ultimate heat sink are available at all times during both normal and accident conditions. The staff in the topic review identified the following item.

A formal inspection program as outlined in Regulatory Guide 1.127 has not been established for the site flood control structures or the service water reservoir. The staff position is that such program should be formalized and that the frequency schedule and a copy of the developed inspection checklist for each structure should be submitted for staff review.

By letter dated January 19, 1984, the licensee committed to develop a program in accordance with Regulatory Guide 1.127. The proposed program was submitted on June 5, 1984. The program is generally acceptable; however, the staff identified the need to make the following changes: (1) add the north bluff to the list of areas to be examined to ensure that the drainage over the bluff to the ocean is maintained and (2) modify the requirement for checking the north drainage ditch to be annually before the rainy season. The licensee agreed to these changes and will incorporate them into the program before the next scheduled inspection.

During an inspection of the intake structure in 1984, significant degradation of the rebar was discovered. Enhanced surveillance of this structure is appropriate to monitor any similar problems in the future. The licensee agreed to these enhanced inspections in a letter dated October 18, 1984. Also, as discussed in the staff's safety evaluation forwarded by letter dated November 21, 1984, inspections of portions of the seawall should be performed to check for degradation. Details of the intake structure surveillance program were submitted by letter dated October 4, 1985a. The seawall was inspected during the Cycle 9 refueling outage and, as discussed in the licensee's May 6, 1986, submittal, only minor indications were found. The staff finds this acceptable.

4.8 Topic III-4.A, Tornado Missiles

10 CFR 50 (GDC 2), as implemented by Regulatory Guide 1.117, requires, in part, that structures, systems, and components be designed to withstand the effects of a tornado, including tornado missiles, without loss of capability to perform their safety functions. Regulatory Guide 1.117 recommends that structures, systems, and components that should be protected from the effects of a design-basis tornado are (1) those necessary to ensure the integrity of the reactor coolant pressure boundary, (2) those necessary to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition (including both hot standby and cold shutdown), and (3) those whose failure could lead to radioactive releases resulting in calculated offsite exposures greater than 25% of the guideline exposures of 10 CFR 100 using appropriately conservative analytical methods and assumptions. The physical separation of redundant or alternate structures or components required for the safe shutdown of the plant is not considered acceptable by itself for providing protection against the effects of tornados, including tornado-generated missiles, because of the large number and random direction of potential missiles that could result from a tornado, as well as the need to consider the single-failure criterion.

Several components and systems were identified as vulnerable to tornado missiles. It is the staff's position that the licensee should provide protection for sufficient systems and components to achieve and maintain a safe shutdown in the event of a tornado. As discussed under Section 4.5, the licensee has proposed to perform a cost/benefit analysis to determine appropriate plant modifications to protect against the effects of a tornado, including tornado-generated missiles.

The staff will report the results of its review in a supplement to the final IPSAR.

4.9 Topic III-5.A, Effects of Pipe Break on Structures, Systems, and Components Inside Containment

10 CFR 50 (GDC 4), as implemented by Regulatory Guide 1.46 and SRP Section 3.6.2, requires, in part, that structures, systems, and components important to safety be appropriately protected against dynamic effects, such as pipe whip and discharging fluids, that may result from equipment failures.

The licensee has performed a screening analysis of the effects of pipe breaks inside containment using conservative criteria; several interactions remain unresolved.

For these interactions, the safety-related equipment that could be affected by breaks includes the following:

(1) support structures for steam generators, pumps, reactor coolant system piping, component cooling system piping, chemical volume and control system piping, safety injection system piping, and air system piping

(2) residual heat exchanger

(3) valves in the residual heat removal (RHR), safety injection, and chemical volume and control systems

(4) RHR pumps, reactor coolant pump

(5) transmitters

As discussed in the licensee's January 19, and March 30, 1984, submittals, further evaluations including detailed systems/effects analyses and fracture mechanics analyses will be performed to resolve these concerns. The staff finds this commitment acceptable.

Electrical components such as cable trays and raceways were not evaluated during this review because, at the time, the review was to be integrated with modifications required by 10 CFR 50, Appendix R. However, as discussed in Section 4.34, the licensee's approach for attaining compliance with Appendix R has changed.

Issues have been raised under several SEP topics (III-5.A, VI-7.C.2 (see Section 4.25.4), VII-1.A (see Section 4.27), and IX-6 (see Section 4.34)) relating to the degree of physical and electrical separation between cabling in the two

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electric power divisions. It is the staff's position that the licensee should perform reviews of the cable routing for San Onofre Unit 1 considering these issues (among others) to identify any corrective actions necessary to ensure availability of safety-related electrical equipment. The licensee will submit the results of its evaluation of pipe break issues, including cabling, and identify any necessary modifications by January 30, 1987.

4.10 Topic III-5.B, Pipe Break Outside Containment

10 CFR 50 (GDC 4), as implemented by SRP Sections 3.6.1 and 3.6.2 and Branch Technical Position (BTP) MEB 3-1 and ASB 3-1, requires, in part, that structures, systems, and components important to safety be appropriately protected against dynamic effects, such as pipe whip and discharging fluids, that may result from equipment failures.

The licensee has provided screening analyses of the effects of pipe breaks outside containment. As a result of these analyses, the licensee has identified several interactions that failed to satisfy the acceptance criteria. The equipment that may be affected includes the following:

(1) structural beams under east and west feedwater heater platforms
(2) main steam system branch lines
(3) auxiliary feedwater steam supply line
(4) auxiliary feedwater discharge line
(5) nitrogen backup supply for pneumatic components
(6) containment sphere

To finish the review, the licensee has described a study (Phase III) in a letter dated January 19, 1984, that will include

(1) further evaluation of high-energy-line interactions with structural beams

(2) evaluation of electrical components

(3) effects of failure of steam supply line for turbine-driven auxiliary feedwater pump

(4) resolution of other unresolved breaks

The licensee has committed to perform the additional analyses for the interaction described above in a fashion similar to that discussed in Section 4.9. The staff finds this commitment acceptable. The licensee will submit the results of this evaluation and identify any necessary modifications by January 30, 1987.

4.11 Topic III-6, Seismic Design Considerations

10 CFR 50 (GDC 2), as implemented by SRP Sections 2.5, 3.7, 3.8, 3.9, and 3.10 and SEP review criteria (NUREG/CR-0098), requires, in part, that structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes.

The seismic design basis for San Onofre Unit 1 for seismic Category A structures and components is what in today's terminology would be consistent with a 0.25g Housner spectrum operating basis earthquake and a 0.5g Housner spectrum

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safe shutdown earthquake. During the construction permit application review for San Onofre Units 2 and 3, new geologic and seismologic information was developed for the site. The design basis for Units 2 and 3 is a 0.67g modified Newmark spectrum earthquake. The licensee initiated a reevaluation program for San Onofre Unit 1 using a ground motion input of 0.67g Housner spectrum. Following initiation of the SEP in 1978, this ongoing seismic reevaluation program was incorporated into the SEP. The history and status of the seismic reevaluation program are detailed in the staff's July 11, 1986, safety evaluation report.

As part of this reevaluation program and as discussed in the evaluations for Topics II-4.A, B, and C (see Appendix E), the staff determined that the appropriate free-field seismic horizontal response spectrum to use for seismic reevaluation of San Onofre Unit 1 was the Housner spectrum anchored at 0.67g with a 10% increase over a specified range. The vertical spectrum is the Housner spectrum anchored at 0.44g with a 10% increase over a small range. These response spectra are referred to as the modified Housner spectra.

The licensee has completed analyses and modifications (as necessary) to upgrade safety-related structures, systems, and components to the site-specific reevaluation ground motion of the 0.67g modified Housner spectra. The scope of these efforts includes equipment necessary to achieve and maintain cold shutdown and to provide accident mitigation. As noted in Sections 4.23.4, 4.23.5, and 4.23.6, seismic qualification of portions of the component cooling water system, containment purge system, and containment fan coolers ensures the containment isolation function. The seismic reevaluation program is now complete, and this topic is considered resolved.

4.12 Topic III-7.B, Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria

10 CFR 50 (GDC 1, 2, and 4), as implemented by SRP Section 3.8, requires, in part, that structures, systems, and components be designed for the loading that will be imposed on them and that they conform to applicable codes and standards.

4.12.1 Design Codes, Criteria, and Load Combinations

Code, load, and load combination changes affecting specific types of structural elements have been identified where existing safety margins in structures are significantly reduced from those that would be required by current versions of the applicable codes and standards. Specific areas of design code changes potentially applicable to the San Onofre Unit 1 plant have been identified for which the current code requires substantially greater safety margins than did the earlier version of the code, or for which no original code provision existed.

Because of the extensive seismic reevaluation program (as discussed in Sections 1.4 and 4.11) for San Onofre Unit 1, which utilizes design codes such as American Concrete Institute (ACI) 349-76 and American Institute of Steel Construction (AISC) 1978, the staff concluded that the impact of code changes and criteria is being adequately addressed.

The licensee is currently evaluating the ability of structures to withstand the effects of various loads, such as

(1) the effects of groundwater (hydrostatic and hydrodynamic loads) (Section 4.6.1)

(2) the effects of wind and tornadoes (Sections 4.5 and 4.8)

(3) the effects of postulated pipe breaks (Sections 4.9 and 4.10)

(4) the effects of seismic events (Section 4.11)

Under Topic III-7.B, the effects of the combinations of these loads on structures, as prescribed in current NRC acceptance criteria, are to be evaluated. In the submittal dated October 4, 1985, the licensee noted that the specific load combinations identified in the staff's September 21, 1982, evaluation, are being addressed under the topics noted above. Therefore, this topic will be completed when the related issues are finished.

4.12.2 Load Combinations for Reactor Containment

Current staff practice is to assess the capability of the reactor containment to withstand various load combinations, including combined earthquake and loss-of-coolant accident (LOCA) loads. For San Onofre Unit 1, the temperature-pressure conditions resulting from a double-ended main steamline break are more severe than for the design-basis LOCA; therefore, the steamline break was considered for this combination with the 0.67g earthquake.

As part of the topic evaluation, the staff contractor, in a report transmitted by letter dated September 21, 1982, provided an analysis for this combined event that indicated that the containment sphere is under high compressive hoop stress in the sand-filled transition zone. This zone is around the sphere extending 6 ft down from plant grade.

Assessment of the potential for buckling of the shell under this stress is very complex. Inward buckling of the shell could affect containment integrity.

By letter dated March 30, 1984, the licensee provided an analysis that concluded that an adequate margin against buckling exists for the San Onofre Unit 1 sphere. This analysis is currently under staff review. The staff will report on its conclusions in a supplement to the final IPSAR.

4.13 Topic III-7.D, Containment Structural Integrity Tests

10 CFR 50 (GDC 16, 50, and 51), as implemented by SRP Section 3.8.2, requires, in part, that a reactor containment structure be provided and that sufficient margin exist to ensure that under postulated accident conditions the containment can accommodate the effects with consideration for uncertainties in determining material properties and residual and transient stresses. The objective of Topic III-7.D is the evaluation of the original containment structural integrity tests that have been performed against current criteria for such tests.

ASME Code, Section III, Division I, Article NE-6000, specifies that a test pressure of 1.1 times the design pressure be used for the containment structural

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integrity test. At the time of the initial test, the peak calculated pressure (design pressure) was 46.4 psig; therefore, a margin of 1.15 to the test pressure of 53.4 psig existed.

In 1977, the LOCA postaccident pressure was recalculated to be 49.4 psig. This calculation was performed using Revision 3A of the computer code BN-TOP3. In 1981, an updated analysis of LOCA pressure was performed using Revision 4 of BN-TOP3. This revision incorporated code changes made in response to staff comments. The peak pressure was 48.2 psig.

The latest analysis of containment response to a main steamline break resulted in a calculated peak pressure of 53.3 psig. However, the licensee has also performed fracture mechanics evaluations to show that the double-ended main steamline rupture is not a credible event. Smaller line failures result in lower peak pressures.

For the LOCA, for which containment integrity is more important for the protection of public health and safety, the calculated peak pressures provide a margin ranging from 8% to 11%, which is comparable to the ASME Code recommendation of a 1.1 factor. Periodic leakage rate tests have been performed at a containment pressure of 49.4 psig. For the steamline break, the worst-case peak pressure would approach the initial test pressure; however, possible degradation of containment integrity would be much less significant in this case than for the LOCA, and there are margins inherent in the design of the containment to compensate for small differences between test and peak pressures. On the basis of the comparable margin to ASME Code requirements and the lesser risk to containment integrity from a steamline break, the staff finds the results of the integrity test acceptable and no further action is warranted.

4.14 Topic III-8.A, Loose-Parts Monitoring and Core Barrel Vibration Monitoring

10 CFR 50 (GDC 13), as implemented by Regulatory Guide 1.133, Revision 1, and SRP Section 4.4, requires, in part, that a loose-parts monitoring program for the primary system of light-water-cooled reactors be provided. San Onofre Unit 1 does not have a loose-parts monitoring program that meets the criteria of Regulatory Guide 1.133.

A loose-parts monitoring program conforming to the recommendations of Regulatory Guide 1.133 could provide an early detection of loose parts in the primary system that could help prevent damage to the primary system. Such damage relates primarily to

(1) damage to fuel cladding resulting from reheating or mechanical penetration

(2) jamming of control rods

(3) possible degradation of the component that is the source of the loose part to such a level that it cannot properly perform its safety-related function

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Implementation of a loose-parts monitoring program is being considered in Revision 1 to Regulatory Guide 1.133. If the staff decides to implement the recommendations of this revision, then the need to implement a loose-parts monitoring program on operating reactors will be addressed generically.

The following factors were considered in making a recommendation that no loose-parts monitoring program be implemented at this time:

(1) A summary of 31 representative loose-parts incidents at 31 reactors (from the value-impact statement of Revision 1 to Regulatory Guide 1.133) indicates that structural damage occurred as a result of loose parts in only 9 incidents. None of these incidents caused a safety-related accident.

(2) Most loose parts can be detected during refueling inspections.

(3) The results of the limited PRA of this issue for San Onofre Unit 1 showed that eliminating loose parts-induced transients by installing a loose-parts monitoring system would have no effect on risk.

Consequently, this issue is considered complete, and no further action or analysis is necessary at this time.

4.15 Topic III-10.A, Thermal-Overload Protection for Motors of Motor-Operated Valves

10 CFR 50.55a(h), as implemented by Institute of Electrical and Electronics Engineers (IEEE) Std. 279-1971 and 10 CFR 50 (GDC 13, 21, 22, 23, and 29), requires, in part, that protective actions be reliable and precise and that they satisfy the single-failure criterion using quality components. Regulatory Guide 1.106 presents the staff position on how thermal-overload protection devices can be made to meet these requirements.

The objective of this review is to provide assurance that the application of thermal-overload protection devices to motors associated with safety-related motor-operated valves (MOVs) does not result in needless hindrance of the valves' performance of their safety functions.

In accordance with this objective, the application of either one of the two recommendations contained in Regulatory Guide 1.106 is adequate. These recommendations are as follows:

(1) Provided the completion of the safety function is not jeopardized or that other safety systems are not degraded,

    (a) the thermal-overload protection devices should be continuously bypassed and temporarily functional only when the valve motors are undergoing periodic or maintenance testing, or

    (b) those thermal-overload protection devices that are normally functional during plant operation should be bypassed under accident conditions.

(2) The trip setpoint of the thermal-overload protection devices should be established with all uncertainties resolved in favor of completing the safety-related action. With respect to those uncertainties, consideration should be given to

(a) variations in the ambient temperature at the installed location of the overload protection devices and the valve motors

(b) inaccuracies in motor heating data and the overload protection device trip characteristics and the matching of these two items

(c) setpoint drift

To ensure continued functional reliability and the accuracy of the trip setpoint, the thermal-overload protection device should be tested periodically.

In San Onofre Unit 1, two motor-operated valves have thermal-overload protection devices that are not bypassed following an emergency signal, nor has it been shown that their trip setpoints were conservatively set. These valves are the component cooling water (CCW) heat exchanger discharge valves. During power operation, one of the two valves is open and the other is closed. The operating train is rotated weekly. When residual heat removal cooling is desired, both valves are opened to provide full CCW flow. The closed valve is automatically opened on a safety injection signal. Once opened, these valves are not required to change position.

Failure of the closed MOV to open will not result in loss of CCW since the other valve is already open. These MOVs are outdoors in the yard and have hand wheels so they can be manually operated, if necessary.

The limited PRA rated the significance of this issue low because the reduction in failure rates for the MOVs achieved by bypassing the thermal-overload would not have any significant effect on core-melt frequency.

Therefore, on the basis of the CCW configuration, the ability to operate the valves manually, and the low risk significance of this issue, the staff concludes that modifications to the two MOVs are not warranted and considers this issue to be resolved.

4.16 Topic III-10.B, Pump Flywheel Integrity

10 CFR 50 (GDC 4), as implemented by Regulatory Guide 1.14 and SRP Section 5.4.1.1, requires, in part, that methods be provided to minimize the potential for failures of reactor coolant pump flywheels which could generate missiles. The staff in the topic evaluation concluded that the inservice inspections that have been performed on the reactor coolant pump flywheels showed compliance with the guidelines of Regulatory Guide 1.14. However, the staff recommended that additions be made to the inservice inspection program to reflect compliance with the recommendations of the regulatory guide.

By letter dated January 19, 1984, the licensee submitted Engineering Procedure S01-V-2.17, "Reactor Coolant Pump Flywheel Inspection," which describes the inservice inspection requirements and schedule for the flywheels. The frequency and type of inspection required by this procedure are consistent with the regulatory guide recommendations. Therefore, the staff finds this inspection program acceptable and considers this topic to be resolved.

4.17 Topic IV-2, Reactivity Control Systems, Including Functional Design and Protection Against Single Failures

10 CFR 50 (GDC 25), as implemented by SRP Section 7.7, requires, in part, that the reactor protection system be designed to ensure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal of control rods.

The staff in the topic review identified several types of rod motion that could occur as a result of single malfunctions. The rod motions to consider are:

(1) Two banks of control rods may move simultaneously.
(2) A group or bank of shutdown rods may not move when commanded.
(3) A group or bank of control rods may not move when commanded.
(4) A group of shutdown rods could move inadvertently.
(5) A group, bank, or banks of control rods may move.
(6) A shutdown rod or a group or bank of shutdown rods may fall into the core.
(7) A control rod or a group or bank of control rods may fall into the core.
(8) A rod assembly could move in a direction opposite to the one commanded.

The results of the limited PRA indicated that the risk significance of this issue is low because the most important consequence of a rod withdrawal accident is localized power peaking in the fuel bundles in the vicinity of the withdrawn rod. Although localized power peaking could result in some cladding damage, no extensive fuel damage or melting would be expected. In previous comprehensive probabilistic risk assessments such as WASH-1400, it has been shown that the most significant contribution to the overall risk of operation of a nuclear power plant comes from the accidents that involve core melt.

Core performance for control rod misoperation events is addressed under Topic XV-8. The following events are explicitly considered in the Topic XV-8 review: uncontrolled withdrawal of a group and control rod group drop. The two-bank-withdrawal event was not explicitly covered under Topic XV-8. However, as noted in the licensee's letter of August 21, 1984a, the reactivity insertion rate resulting from a two-bank rod withdrawal is within the range of rates considered in the analyses of the control rod group withdrawal event. The results of the group withdrawal analyses, as discussed under SEP Topic XV-8, confirmed that the safety limits are met.

The remaining rod motions that could occur as a result of single failures would not result in a configuration more severe than that considered in the control rod maloperation analyses. In those cases where rods might not move when movement was commanded by the rod control system, the rods would still scram if required. Rod position indications and limits on allowable misalignments ensure that adverse power distributions do not occur.

Therefore, on the basis of the above discussion, the staff finds the analyses sufficient and considers this topic to be resolved.

4.18 Topic V-5, Reactor Coolant Pressure Boundary (RCPB) Leakage Detection

10 CFR 50 (GDC 30), as implemented by Regulatory Guide 1.45 and SRP Section 5.2.5, prescribes the types and sensitivity of systems and the seismic, indication, and testability criteria necessary to detect leakage of primary reactor coolant to the containment or to interconnected systems. Regulatory Guide 1.45 recommends that at least three separate leak detection systems be installed in a nuclear power plant to detect unidentified leakage from the RCPB to the primary containment of 1 gallon per minute (gpm) within 1 hour. Leakage from identified sources must be isolated so that the flow of this leakage may be monitored separately from unidentified leakage. The detection systems should be capable of performing their functions after seismic events that do not require shutdown and be capable of being checked in the control room. Of the three separate leak detection methods recommended, two of the methods should be (1) sump level and flow monitoring and (2) airborne particulate radioactivity monitoring. The third method may be either monitoring the condensate flow rate from air coolers or monitoring airborne gaseous radioactivity. Other detection methods--such as monitoring humidity, temperature, or pressure--should be considered to be indirect indications of leakage to the containment. In addition, provisions should be made to monitor systems that interface with the RCPB for signs of intersystem leakage through methods such as monitoring radioactivity and water levels or flow.

On the basis of its review of the available information for the leakage detection systems at San Onofre Unit 1, the staff in the topic evaluation concluded that the systems used at San Onofre Unit 1 do not meet all of the recommendations of Regulatory Guide 1.45. Specifically, the staff determined that:

(1) The systems used for the detection of leakage from the RCPB to the containment consist of the minimum three recommended in Regulatory Guide 1.45 plus additional systems. However, at the time the staff SER (letter dated March 7, 1983) was issued, the licensee had not determined the system sensitivities and response time.

(2) Information on the description of the systems used to monitor leakage from the reactor coolant system to secondary systems is incomplete.

(3) The San Onofre Unit 1 Technical Specifications do not contain requirements for the operability of the leakage detection systems.

(4) None of the recommended leakage detection systems has been demonstrated to remain functional following a safe shutdown earthquake.

(5) Not all of the leakage detection systems have provisions for testing operability and calibration during plant operation.

4.18.1 Leakage Into Containment

At San Onofre Unit 1, the following systems are provided for RCPB leak detection:

(1) sump level monitoring
(2) sump pump actuation monitoring
(3) airborne particulate radioactivity monitoring

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(4) airborne gaseous radioactivity monitoring
(5) containment atmosphere pressure monitoring
(6) containment atmosphere humidity monitoring
(7) containment atmosphere temperature monitoring

Also, the amount of leakage from the RCPB can be determined by performing the reactor coolant system hot leak rate test (San Onofre Unit 1 Operating Instruction S01-12.2.7). This test is run at least every 7 days, and the test run time is 4 hours.

4.18.1.1 System Sensitivity

By letter dated February 24, 1984, the licensee provided the following additional information on leakage detection system sensitivity.

With the sphere sump pump system, a 1-gpm leak can be detected in 80 min when a level switch starts a sump pump. Pump start is annunciated in the control room. In response to the pump start alarm, the operator logs the pump start time and then the pump stop time. Lights in the control room show pump status (running or not). A second pump starts at a higher setpoint; the annunciator is common to both. If the pumps do not start, another level alarm is reached after 86 additional minutes.

If the pump starts, but because of equipment failure the alarm does not sound, the pump will pump out the sump contents to the decontamination drain tank. The detection time in this case would be more variable because it would depend on whether or not an operator noticed the pump running lights or how full the drain tank was (there is a high-level alarm, but the tank is considerably larger than the sump and other sources drain there as well).

Smaller leaks can also be detected by this method, but the time to detect them will most likely depend on how quickly the leaks develop, what the previous leakage was, and other factors.

There are also sump level indicators with control room readout. These systems are sensitive enough to show a 1-gpm leak but are dependent on plant operators noticing any changes because no alarms are provided.

Using the airborne particulate monitor and assuming a base level isotopic activity, a 1-gpm leak can be detected (control room alarm) in 1 hour.

Other indications include the following.

The airborne gaseous radioactivity monitor has a 1-gpm sensitivity, but detection time is longer than 1 hour. The sensitivity is dependent on the normal radiation level, which is itself dependent on power level, failed fuel, and core life. For a small leak and low radiation levels, this monitor may not detect the leak. At best, it can detect a leak after about 10 hours.

Containment pressure, temperature, and humidity alarms can detect a 6.7-gpm leak within 1 hour. A 1-gpm leak will not be detected. These alarms are only considered as indirect indications of leakage to the containment.

The RCPB-to-containment leakage detection systems at San Onofre Unit 1 have the capability to detect a 1-gpm leak, but the detection time is longer than 1 hour. The longer time to achieve this sensitivity is not considered to be of significance unless the resolution of Topic III-5.A, "Effects of Pipe Break on Structures, Systems, and Components Inside Containment," demonstrates that the current leak rate sensitivity is not considered adequate.

The staff concludes that these leakage detection systems are adequate to detect a 1-gpm leak in an acceptable period of time unless the continuing review under Topic III-5.A identifies the need for improved leak detection capability. Because the issue of detection sensitivity will be resolved in another topic (see Section 4.9), this issue is considered complete.

4.18.1.2 Operability Requirements

The San Onofre Unit 1 Technical Specifications do not contain limiting conditions for operation or surveillance requirements regarding the operability of leakage detection systems, as recommended by Regulatory Guide 1.45 and the Westinghouse Standard Technical Specifications (NUREG-0452).

It is the staff's position that such specifications are necessary to ensure operability of the leakage detection systems and, therefore, timely detection of leakage from the reactor coolant system. The licensee has agreed to provide proposed Technical Specifications by November 14, 1986.

4.18.1.3 Seismic Qualification

The leakage detection systems do not meet the recommendations of Regulatory Guide 1.45 with regard to operability following a seismic event. Therefore, it is the staff's position that the licensee should provide at least one leakage detection system that will remain operable following a safe shutdown earthquake, or that the licensee should provide procedures that specify actions to be taken for a seismic event to monitor for possible leakage because non-seismically qualified leak detection systems may not function properly. The licensee committed to provide the required information by November 14, 1986.

4.18.1.4 Testability

Two of the required leakage detection systems, the airborne particulate and gaseous monitoring systems, can be tested during normal operation. The sump level monitoring system does not meet the recommendations of Regulatory Guide 1.45 with regard to direct testability during plant operation. However, the performance of the weekly reactor coolant system hot leak rate test would serve as an indirect indication of the operability of the sump level monitoring system. Therefore, considering all the means provided for leak detection, the staff finds that the existing testing capabilities are acceptable.

In summary, it is the staff's position that the leakage detection systems currently installed at San Onofre Unit 1, although not meeting the explicit recommendations of Regulatory Guide 1.45, are adequate to detect small reactor coolant pressure boundary (RCPB) leakage within an acceptable timeframe. However, the staff recommends that the plant Technical Specifications be upgraded to include operability requirements for these systems and at least one RCPB-to-containment leakage detection system should be upgraded for seismic qualification. However, additional staff recommendations could be forthcoming if the licensee's analysis of pipe breaks inside containment (see Topic III-5.A, Section 4.9) demonstrates that other system upgrades are warranted.

4.18.2 Intersystem Leakage

Provisions are made to monitor reactor coolant leakage to interconnecting systems, namely the component cooling system and the main steam system. Intersystem leakage from the reactor coolant system (RCS) into the secondary system is monitored by the condenser air ejector monitor and the steam generator liquid monitor. A 1-gpm leak is within the sensitivity range of the instruments, but the alarm setpoints are such that the leak would not be detected within 1 hour.

Leakage between the RCS and the component cooling water system is monitored by high- and low-level alarms and a radiation detector. A 1-gpm leak could be detected in 6.4 hours. The component cooling water surge tank is classified as a seismic Category A tank. As noted in Section 4.28.1 (Topic VII-3), the level sensor and alarms are not redundant, although a local sight gauge, checked once per shift, is also available.

The secondary system air ejector and the steam generator blowdown monitors need not be seismically upgraded because these are redundant components, and manual sampling for secondary activity can be performed if the monitors both fail. Radioactive leakage from the secondary system will also be monitored by instrumentation required by TMI Action Plan Item II.F.1, "Noble Gas Effluent Monitor."

The staff has concluded that intersystem leakage would not contribute significantly to overall risk (see Sections 4.19 and 4.32) and, because of the available leakage detection systems, the staff finds that the capability to detect intersystem leakage at San Onofre Unit 1 is acceptable. The staff considers this issue to be resolved.

4.19 Topic V-10.A, Residual Heat Removal System Heat Exchanger Tube Failures

10 CFR 50 (GDC 34) and 10 CFR 100 (Appendix A), as implemented by SRP Section 9.2.1, require, in part, that a residual heat removal system be provided with leakage-detection and isolation capability to limit possible releases of radioactive coolant to the environment.

SRP Section 9.2.1 requires that the service water system include the capability for detection and control of radioactive leakage into and out of the system and prevention of accidental releases to the environment.

The residual heat removal (RHR) system at San Onofre Unit 1 is normally at a higher pressure than the component cooling water (CCW) system. Therefore, a tube failure in the RHR heat exchangers would result in contamination of the CCW system. Furthermore, because CCW pressure at the CCW heat exchanger is greater than that of the salt water cooling system at this heat exchanger, radioactive leakage to the environment could occur in the event of the highly unlikely simultaneous failure of tubes in a combination of one (or both) of the two RHR heat exchangers and one (or both) of the CCW heat exchangers. San Onofre Unit 1 is provided with CCW system instrumentation to detect such an occurrence. As defense against leakage to the environment, the CCW system incorporates a radiation detector, and the surge tank of this system has high- and low-level alarms, which will indicate leakage either into or out of the system.

The results of the limited PRA showed that because contamination from in-leakage of component cooling water to the primary water system is a very low-frequency event, it is of low risk significance. This is based on the fact that this event can only occur during refueling outages when primary coolant system pressure is less than CCW system pressure.

For leakage to the environment from the reactor coolant system to occur, tube failures in both the RHR and component cooling heat exchangers would be necessary. The CCW surge tank level instruments should detect inleakage or outleakage, inservice inspection is performed on the heat exchangers, and there is a radiation monitor on the CCW system. The results of the limited PRA showed that the risk from this event is also low.

4.19.1 Radiation Monitoring

The San Onofre Unit 1 salt water cooling system does not incorporate a radiation monitor as required by SRP Section 9.2.1, and the staff in its topic evaluation recommended that the licensee should install one. As an alternative, surveillance and operability requirements for the CCW system radiation monitor could be included in the Technical Specifications. As noted in the licensee's letter of January 30, 1984, the Radiological Effluent Technical Specifications (RETS) (issued August 27, 1984) require channel checks, calibration, and tests of the CCW radiation monitor. The staff finds the RETS requirements alternatively acceptable and, therefore, this issue is considered to be resolved.

4.19.2 Sampling

The staff in the topic evaluation concluded that the CCW system should be sampled for chlorides and that sampling should be done during shutdown modes. Although station procedures cover primary sampling requirements, the staff concluded that Technical Specifications for leak detection (into the primary system) limits and sampling frequency for the reactor coolant system should be established.

By letter dated November 7, 1983, the licensee noted that the present sampling and chemical control procedure for the primary system, which includes sampling of the CCW system, provides for monthly sampling of the CCW for chlorides and sampling requirements while shut down. In a letter dated January 19, 1984, the licensee noted that the chemistry limits for chlorides, fluorides, and oxygen in the procedure comply with the Westinghouse Standard Technical Specification (NUREG-0452) limits. The staff concludes that these procedures are adequate and Technical Specification changes to add these limits are not necessary.

4.19.3 Testing of Recirculation Heat Exchanger

The review under Topic VI-7.A.3 noted that the recirculation heat exchangers are not tested for leakage. This issue was addressed under Topic V-10.A because the concern relates to leakage through a heat exchanger that could result in introduction of sump water (following a loss-of-coolant accident (LOCA)) into the component cooling water system.

The recirculation heat exchanger is used to cool sump water during the recirculation cooling mode after a LOCA. There is only one heat exchanger. If a leak existed or developed, radioactive water could enter the component cooling water system if the relative pressures in the two systems allowed it. However, the pressure in the heat exchanger is normally higher than peak containment pressure. Furthermore, because the CCW system is a closed loop, an additional failure would be necessary for a release after any leakage into the CCW.

The heat exchanger is maintained solid on the recirculation side with component cooling water passing through the heat exchanger through a miniflow line. Therefore, if a tube failure existed, water would leak from the CCW into the recirculation heat exchanger. Such a leak could be detected by falling CCW level in the surge tank. The CCW system is hydrotested in accordance with ASME Code, Section XI requirements. On this basis, the staff concludes that adequate testing is performed and that the potential for radiological release is minimal. The staff concludes that no further action is necessary.

4.20 Topic V-11.A, Requirements for Isolation of High- and Low-Pressure Systems

10 CFR 50.55a, as implemented by SRP Section 7.6 and Branch Technical Position (BTP) ICSB 3, requires that systems with lower design pressure ratings should be isolated from the reactor coolant system when it is at a pressure above the system design rating.

The staff in its safety evaluation concluded that the following systems did not fully satisfy current licensing criteria for high- and low-pressure isolation:

(1) chemical and volume control system
(2) safety injection system
(3) long-term recirculation system

4.20.1 Chemical and Volume Control System

4.20.1.1 Charging Pump Discharge Valves

The staff in the topic evaluation concluded that the charging pump discharge valves do not satisfy the applicable high-to-low-pressure system interlock criteria. The low-pressure portions of the chemical and volume control system (CVCS) are on the suction side of the charging pumps.

The only high-pressure interface with the low-pressure piping in the CVCS occurs across the charging pump discharge check valve for an idle charging pump. Pressurization of the suction piping from the operating pump could occur if the discharge check valve in the idle leg failed and the suction side

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was isolated by closing the manual valve. For a loss-of-primary-coolant inventory to occur through the suction line, the other pump must be tripped and the check valve at the RCS loop must also be failed.

The scenario considered in the limited PRA was reverse leakage past the two check valves during operation, with failure of the air-operated isolation valve to close. The frequency of this event is estimated to be approximately 1 x 10^{-6} per year. Although the magnitude is low, intersystem LOCAs bypassing containment can have significant consequences.

However, for the idle pump's suction line to be pressurized, the manual valve on the suction side must be closed (see Figure V-11.A.1 of Appendix D). This aspect was not considered in the PRA calculation. Furthermore, control valve FCV-1112 is also in the flow path and would have to stay open for the LOCA path to exist. Also, inservice testing (full stroke exercising open and closed) of the discharge check valve is performed every 3 months. The suction side valve is normally open and is on the monthly safety-related valve alignment checklist. The other check valve is tested each refueling outage.

If neither charging pump is running, the leakage path could develop without closure of the suction valve (i.e., if both check valves fail). However, operation of the plant with neither charging pump running is very limited. Therefore, because of the valve testing program and the valve alignment checklist changes, the staff concludes that modifications to the CVCS to meet the high-to-low-pressure interlock criteria are not warranted and considers this issue to be resolved.

4.20.1.2 Letdown Piping

The isolation valves of the letdown line do not have pressure-related interlocks to automatically close if RCS pressure increases above system design pressure. A relief valve is provided downstream of these orifices. The staff concern was that for an event that isolated the letdown system outside containment coupled with a failure of the relief valve, a LOCA (isolatable) might occur. Therefore, the staff recommended in the topic evaluation that the licensee should provide a redundant relief valve or show that the radiological consequences of such a break are acceptable. Under Topic XV-16, the consequences of the limiting small-line break outside containment (larger than the CVCS letdown) were shown to be acceptable if operator action to isolate the break occurred in 20 minutes. This time period is considered adequate for isolation of a letdown line failure considering available indications and autoclosure features on the letdown line valves (on low pressurizer level). The staff concludes that modifications to the CVCS letdown piping are not warranted and, therefore, this issue is resolved.

4.20.2 Safety Injection System

Each safety injection branch has a motor-operated valve (MOV) and a check valve in series isolating the reactor coolant system (RCS) from the feedwater discharge piping. The MOVs do not have pressure-related interlocks to prevent them from opening when RCS pressure is above safety injection system (SIS) design pressure. A limit of 5-gpm leakage for the check valves is established in the plant Technical Specifications.

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The results of the limited PRA showed that the initiation of a LOCA due to reverse leakage through these lines resulting from an MOV left open following its periodic testing and failure of the check valve is considered to be of medium risk significance. The limited PRA also noted that if procedures are established so that a second operator must verify the correct position of the MOV following the test, the LOCA frequency can be reduced.

As noted, in the licensee's January 19, 1984, letter, the check valves and MOVs are tested as part of Surveillance Procedure S01-12.9-9, "Safety Injection System Check Valve Test." This procedure instructs the operator to open and close the MOV during the test. During startup, the MOVs are verified closed as part of Procedure S01-4-17, "Safety Injection System Operation." Procedure S01-4-39, "Safety Injection System Alignment," requires verification of the MOVs in the closed position before startup. As part of the shift review, the safety-related valve status is verified in the control room according to Procedure S01-14-5, "Operations Shift Relief and Status Logs." MOV position indication is checked during the inservice testing of these valves (each refueling outage).

It should be noted that the design pressure of the feedwater discharge piping is 1,400 psig. Considering the margins inherent in the design of this piping, the ASME Code allows a pressure of 60% over design pressure under faulted conditions (2,240 psig). The two power-operated relief valves are set to open at 2,190 psig. The staff estimates that the probability of failure of this piping if exposed to RCS pressure is less than 0.5.

The staff concludes that, on the basis of the SIS design pressure and margin, procedures to verify that the MOVs are closed at two separate times before plant startup, and the Technical Specification limit on check valve leakage, modifications to the SIS are not warranted and that this issue is resolved.

4.20.3 Long-Term Recirculation System

The long-term recirculation lines from the charging pumps have a check valve, two motor-operated valves, and an air-operated valve in series. This flow path is used only for postaccident response and the valves are normally closed. The discharge piping is designed for full RCS pressure; the safety concern is pressurization of the charging pump suction piping similar to the case discussed in Section 4.20.1.1 above.

Although no system interlocks are present, the remote possibility of misaligning four valves in series and the testing of the check valve together with acceptable system procedures for valve alignment verification form an adequate basis for not making modifications to this system. This issue is resolved.

4.21 Topic V-11.B, Residual Heat Removal System Interlock Requirements

10 CFR 50.55a, as implemented by SRP Section 7.6 and BTP ICSB 3, requires, in part, that the motor-operated valves (MOVs) used for the isolation of the RCS from other systems that have lower design pressure ratings should have independent and diverse interlocks. These interlocks should prevent the opening of the MOVs until the RCS pressure is below the system design pressure, and close them automatically when RCS pressure increases above the system design pressure.

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4.21.1 Residual Heat Removal System Interlocks

The residual heat removal (RHR) system does not satisfy current acceptance criteria with respect to pressure interlocks. Isolation on both the suction and discharge sides is provided by two MOVs in series. All the MOVs have position indication in the control room and are normally closed during plant operation. The inboard set of valves has a pressure-related interlock to prevent them from opening until RCS pressure is below RHR system design pressure. The other set of valves is under administrative control. In accordance with plant operating procedures, the valves are not opened to place the RHR system in service until the RCS pressure is reduced to 350 psi.

Failure of the interlock could result in overpressurization of the RHR system if an operator opened the RHR isolation valves when RCS pressure was too high. The results of the limited PRA showed that the probability of inadvertent opening of the isolation valves at high pressure (with failure of the pressure interlock) is approximately 1×10^{-7} per year; thus, this issue is of low importance. This value is dependent on assumed human error rates for opening the valves and the probability of recovery from the accident. Thus, the staff believes there may be large uncertainty in this value. However, it should be noted that the RHR system is totally inside containment; therefore, even if the RHR system were to fail, a LOCA bypassing containment would not occur. The RHR system is not part of the emergency core cooling system equipment; thus, the capability to mitigate the LOCA is not affected. On the basis of the above, the staff concludes that the features provided for RHR system isolation are adequate and, therefore, this issue is resolved.

4.21.2 Overpressurization Protection of Residual Heat Removal System

No interlocks are provided to automatically close RHR system isolation valves on increasing pressure. The staff in its topic evaluation concluded that this difference from current criteria was acceptable on the basis of availability of the alarm and relief capacity of the overpressure mitigation system (OMS) as well as the relief valve in the RHR system. This conclusion is also supported by the staff study on overpressure protection systems (AEOD/C401), which found that automatic isolation of the RHR system may exacerbate an overpressurization transient and that sufficient relief capacity from the OMS can eliminate the concern of RHR system overpressurization.

Another AEOD study (AEOD/C503) on decay heat removal problems at PWRs dated December 1985 has also recommended that autoclosure interlocks be removed, if adequate relief capacity is provided, to prevent inadvertent isolation of the RHR system.

During cooldown present procedures place the RHR system into service at 350°F and 350 psi. The surge volume in the pressurizer and the relief valve are available for overpressure protection of the RHR system if the OMS is not available. However, to provide protection for the RHR system, the staff recommended in its topic evaluation, forwarded by letter dated November 12, 1982, that Technical Specifications should be provided so that the OMS will be operable when the RHR system is in operation.

The licensee has agreed to submit the requested Technical Specification changes by November 19, 1986.

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4.22 Topic VI-1, Organic Materials and Postaccident Chemistry

10 CFR 50 (GDC 1, 4, 14, 31, 35, and 41 and Appendix B), as implemented by SRP Sections 6.1.1 and 6.1.2 and Regulatory Guide 1.54, requires, in part, that structures, systems, and components important to safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operating and postulated accident conditions. In particular, paints and organic materials used inside containment should not adversely affect the functions of the engineered safety features.

The safety objective of this topic is to ensure that protective coatings inside the containment do not consist of material (such as cellulose, hydrocarbons, or chlorides) that could decompose in radiation environments, create a hazardous hydrogen-rich environment, or cause material failures. The staff in its topic evaluation, therefore, recommended that the licensee commit to a periodic inspection and repair program.

By letter dated March 30, 1984, the licensee submitted the results of the inspection of the containment coatings that was performed during a plant outage as well as plans for future inspections and repair. On the basis of the inspection, the licensee performed the following paint repairs:

(1) Touch up of reactor coolant pumps, containment hatch door, and heating, ventilation, and air conditioning (HVAC) recirculation fans.

(2) Repair to coatings on some piping with salt and pepper rusting and on piping where coating was applied over mill varnish.

(3) Repair to coating on exterior surface of HVAC equipment where delamination may have occurred.

The licensee also agreed to develop a program to perform future periodic inspections of the containment coatings at intervals to coincide with containment type A testing. This will result in a frequency comparable to the staff recommendation of once every 3 years. Therefore, the staff finds this commitment acceptable.

4.23 Topic VI-4, Containment Isolation System

10 CFR 50 (GDC 54, 55, 56, and 57), as implemented by SRP Section 6.2.4 and Regulatory Guides 1.11 and 1.141, requires isolation provisions for the lines penetrating the primary containment to maintain an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment. Under Topic VI-4, the containment isolation system is reviewed. This includes a reexamination of the penetrations for compliance with GDC 54 through 57 as well as a review of the electrical, instrumentation, and control design. The results of this review, including identified differences from criteria, are discussed below.

The results of the limited PRA for this topic showed that differences in the existing isolation provisions are of low importance to risk because the absolute failure probability of the penetrations of concern were small in comparison with the overall containment failure probability.

4.23.1 Electrical Aspects

The scope of the review and evaluation performed under Multiplant Generic Activity B-24 and Office of Inspection and Enforcement (IE) Bulletin 80-06, "Engineered Safety Feature (ESF) Reset Controls," encompasses the electrical aspects of this topic. Staff evaluations on the electrical issues associated with containment isolation were issued on February 17 and December 6, 1982. Specific issues raised in those evaluations are discussed below.

4.23.1.1 Purge Lines

As part of the review of Generic Issue B-24, the staff concluded that maintaining the 24-in.-diameter purge line isolation valves closed during modes 1 through 4 would preclude release of radioactivity through these lines should a loss-of-coolant accident occur.

The licensee submitted a proposed Technical Specification change on September 9, 1983, that would require a valve in each purge line to be locked closed during modes 1 through 4. The staff issued License Amendment No. 71 on February 17, 1984, to implement this requirement. This issue is therefore resolved.

4.23.1.2 Key Control and Control Panel Access Procedures for Sequencer Doors

In the December 6, 1982, topic evaluation, the staff found that the sequencer test switches were not the spring-loaded type that automatically return to the non-test position. Therefore, it was possible that both sequencers could be placed in the test mode at the same time. A common annunciator for "Sequencer in Test" is provided for both sequencers and thus would not show that both sequencers were in the test mode. Although administrative controls have been established to prevent this, no physical features have been provided to augment these controls as recommended by staff guidelines. As discussed in the licensee's November 22, 1982, submittal, each of the sequencer test panels has a lockable door with an indicator light. The licensee proposed to revise the test procedures to require that only one door light be on when the "Sequencer in Test" annunciator is lit.

The control panel access procedures in conjunction with the "door open" control panel lights for the sequencer doors will provide added assurance that both sequencers are not in the test mode at the same time.

As discussed in the licensee's July 28, 1986, letter, the necessary procedures have been implemented. The staff finds this acceptable and considers this issue to be resolved.

4.23.1.3 Redesign of BLOCK SIAS Annunciator Window

In the December 6, 1982, safety evaluation, the staff concluded that the annunciator for blocking the safety injection actuation signal (SIAS) should be modified to clarify the effects of blocking the signal. This modification entails redesigning the BLOCK SIAS annunciator window to indicate that when the SIAS is blocked, the containment spray signal and the SIAS inputs to the containment isolation signal are also blocked. Implementation of this modification does not entail physical changes to the present operating configurations, and, therefore, the degree of safety will not be significantly enhanced. Furthermore, during normal plant cooldown, the automatic SIAS is manually blocked to prevent inadvertent actuation of safety injection. An RCS pressure bistable element generates an alarm (Alert to BLOCK SIAS) at 1,750 psig to advise the operator that the SIAS should be manually blocked before pressure is reduced as part of the cooldown. Should safety injection be required after blocking, manual actuation of both injection flow trains is possible by deliberate sequencer actuation via manual initiate pushbuttons located on each sequencer remote surveillance panel in the main control room. Automatic reset of the safety injection block circuits will occur at a pressure of 1,900 psig in the pressurizer as the system is being brought to operating conditions. At that time, the safety injection block permissive indication will extinguish, indicating that the permissives have been reestablished.

In regard to the impacted containment spray, actuation can be initiated as required by manually starting the refueling water pump and opening the appropriate valves.

The containment spray system is actuated on a two-out-of-three high containment pressure signal and initiation of the SIAS. In the event the sequencer is reset before the receipt of the two-out-of-three signal (reset BLOCK SIAS) initiation of containment spray could be defeated. The containment spray actuation circuitry has been modified to include a seal-in relay contact to seal in the SIAS. Therefore, reset of the sequencer will not defeat the actuation of the containment spray system. The sealing of the SIAS is released on reset of the containment spray actuation signal.

On the basis of the information provided above, the blocking of the automatic initiation of more than one engineered safety feature (ESF) occurs only when operating modes are changed, at which time this configuration is desirable. The benefit gained by implementation of the annunciator modification is limited to additional information annunciated on the permissive display panel. Since operation of the SIAS block switch is an integral part of normal plant cooldown and part of routine operating procedures, reactor operators receive training to ensure familiarity with system operation. This familiarity includes operator awareness of the additional impacted ESFs and the procedures necessary to initiate those systems, should actuation be required. The current operator training program provides adequate information on the system interaction, and implementation of the proposed modification will not significantly enhance operator awareness. Therefore, implementation of the proposed annunciator modification will not significantly enhance safety. Furthermore, this modification does not entail changes in system operation. For these reasons, this modification is not warranted and the staff considers this issue to be resolved.

4.23.1.4 Automatic Loading of Diesel Generator Radiator Fans

The staff in the topic evaluation concluded that the fans that provide cooling for the diesel generators should be automatically loaded on a safety bus when the diesel generators start. The staff concluded that the diesel generator could be running without adequate cooling capability and thus might overheat.

In a letter dated January 19, 1984, the licensee stated that the diesel generators will start coincident with a safety injection actuation signal (SIAS), loss of offsite power (LOP), or SIAS/LOP. In the event of an SIAS, the diesel generators will start and the diesel generator radiator fans will be loaded automatically on the safety bus, which is powered by offsite power. In the event of an LOP, the diesel generators will start but will initially run with zero load. In this situation, the initial operator action is to attempt to regain power from the switchyard. If power cannot be regained from the switchyard, the buses will be manually loaded on the running diesel generators, at which time, operation of the radiator fans will be initiated. In the event of an SIAS/LOP, the diesel generators will start and be automatically loaded. Once the diesel generators have reached full speed and voltage (approximately 10 sec after the event), the sequencer will cause the diesel generator circuit breaker to close, thereby energizing the buses that supply power to the radiator fans. Therefore, the fans will start 10 sec after the diesel generators for the SIAS/LOP event.

Thus, initiation of the diesel generator radiator fans by loading the bus requires operator action only in the event of an LOP. Approximately 30 min are available to initiate fan cooling for the diesel generators running at no load before the diesel generators start to overheat. The staff concluded that the licensee should review plant operating procedures to ensure that precautions are included regarding the time limits for diesel generator operation unloaded.

On the basis of the above discussion, the staff concludes that, with appropriate procedures, adequate time is available for operator action when it is needed. These procedural checks were completed before restart from the Cycle 9 outage. The staff finds this acceptable.

4.23.1.5 Override Capability for Reactor Coolant Sample Line Isolation Valves

This issue is discussed in Section 4.23.2.

4.23.2 Valve Actuation

The following penetrations were identified during the topic review as having remote manual valves inside containment as isolation valves instead of automatic isolation valves as required by GDC 55 and 56:

Line	Penetration	Valve numbers
Pressurizer sample	46	CV951, 953 (inside); CV992 (outside)
Reactor coolant loop samples	47	CV955, 956 (inside); SV3302 (outside)
Residual heat exchanger sample	48	CV962 (inside); CV957 (outside)
Pressurizer relief tank gas sample	49	CV948 (inside); CV949 (outside)

The isolation configuration for these 3/8-in. sample lines consists of a normally closed remote manual valve (inside) in series with an automatic valve (outside). All of the valves are normally closed except when samples are being

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taken. The automatic valves have a common override switch so that samples can be taken even if a containment isolation signal is present. The override does not result in automatic reopening of any valve.

In regard to the manual override of the automatic isolation valves outside containment, Section II-E.4.2 of NUREG-0737 states that reopening of containment isolation valves shall require deliberate action. This requirement is satisfied by the fact that two actions are required to open each line: one action to override the containment isolation signal and one action to open the valve.

Providing modifications to these penetration lines to meet the explicit provisions of GDC 55 and 56 would not significantly improve the capability to isolate these lines.

On the basis of the above considerations, the staff concluded that these lines have adequate isolation provisions and no modifications are warranted. Accordingly, this issue is considered to be resolved.

4.23.3 Valve Type

The staff in the topic evaluation noted that the following penetrations have check valves outside containment as isolation valves instead of automatic isolation valves as required by GDC 56 or 57:

Line	Penetration
Instrument air header	13
Steam generator feedwater supply	7
Steam generator feedwater supply	8
Steam generator feedwater supply	9

Penetration 13 has check valves both inside and outside containment as well as a pressure-regulated valve outside containment. The pressure-regulated valve closes automatically when supply pressure drops below 60 psig. This is higher than the peak accident design pressure. The valve will be automatically closed whenever the air supply pressure will not ensure positive inflow to containment. The check valve also provides isolation for this 1½-in. line. The staff concludes that this valving arrangement provides adequate isolation capability and, therefore, no modifications are warranted.

The configuration of the feedwater lines was identified as a difference from current criteria because the boundary classification change (safety-related/non-safety-related) occurred at the check valve. However, the check valve is backed up by both a flow control valve and an MOV on the main feedwater lines and by a flow control valve on the bypass line. These valves are automatically closed on receipt of a safety injection actuation signal. Therefore, the staff concludes that this valving configuration provides adequate isolation for these lines.

The ½-in. chemical feed lines connect to the main feedwater lines on the containment side of the check valve. Therefore, these lines are part of the isolation boundary. A check valve serves as the isolation valve. The staff has concluded in previous risk assessments for other SEP plants that replacing the check valve with an automatic isolation valve would not significantly improve isolation reliability. Also, the potential leakage through such a small line, even if the valve were to catastrophically fail, is a negligible contributor to containment release. Therefore, the staff finds this valving arrangement acceptable and considers this issue to be resolved.

4.23.4 Valve Location

The following penetrations have both isolation valves outside containment instead of one inside and one outside, as required by GDC 56:

Line	Penetration
Containment sphere purge air	15
Containment sphere exhaust air	16

One valve in each line is maintained locked closed whenever the plant is in operation. The relative benefits of one valve inside and one valve outside rather than two valves outside containment have been evaluated in other SEP integrated assessments, and the conclusion was that little improvement could be shown in moving a valve inside containment. This is because the probability of failure of both valves was greater than the probability of failure of the pipe between the containment and first isolation valve. These lines are also included within the scope of systems being evaluated under Topic III-6 for their seismic integrity (see Section 4.11). Because of the minimum improvement in containment isolation capability and low importance of containment leakage to overall risk, corrective modifications are not recommended. The staff considers this issue to be resolved.

4.23.5 Isolation of Closed Systems

The following penetrations are lines that either enter or leave the containment sphere but are not open to the sphere free volume or the outside atmosphere. They are not provided with either automatic, remote manual, or locked-closed isolation valves as required by GDC 57.

Line	Penetration
Component cooling water supply and return	29 through 41

These lines are equipped with local manual valves outside containment and, in some cases, check valves inside containment.

The component cooling water (CCW) system is normally always in operation and provides postaccident functions. Thus, these lines will be pressurized when isolation is required. The CCW system is leak tested every 40 months and is hydrotested in accordance with ASME Code, Section XI requirement to check for leakage. The CCW system is within the scope of systems for which seismic reevaluation and upgrading is continuing (see Section 4.11). The CCW lines inside containment are evaluated as potential targets for pipe break effects (see Section 4.9). On the basis of system use, the seismic reevaluation, and pipe break considerations, the staff concludes that adding remote manual or automatic isolation valves to these lines is not warranted. However, it is the staff position that the licensee develop procedures that would identify when these valves need to be closed to ensure containment integrity (e.g., when the system is depressurized or there is a break in the CCW system). The licensee has proposed to evaluate the provisions for isolating CCW system lines and to implement any needed procedural changes by November 14, 1986.

4.23.6 Isolation of Air Handling Unit Cooling Lines

The following penetrations are lines that enter or leave the containment sphere but are not open to the sphere free volume or the outside atmosphere. GDC 57 requires at least one isolation valve that is either automatic, locked closed, or capable of remote manual operation.

Line	Penetration
Cooling water to air handling units	4, 5, 6

The licensee has indicated that lines 4, 5, and 6 are part of an essential closed system inside containment. Isolation provisions for each of these penetrations consist of a single remote manual isolation valve located outside containment.

This arrangement satisfies the requirements of GDC 57. However, for GDC 57 to apply, the closed system inside containment should be of safety-grade design. These lines are designated seismic Category A and are being evaluated under Topic III-6. Protection from pipe break effects is being considered under Topic III-5.A. Therefore, subject to resolution of these topics, this issue is considered to be complete.

4.23.7 Isolation of Branch Lines

The following penetrations have branch lines outside containment between the isolation valve and the containment, with open manual valves as containment ioslation valves:

Line	Penetration
Refueling water	1, 2
Main steam	54, 55

4.23.7.1 Refueling Water Lines

Line 1 (refueling water supply) branches into four parallel lines inside containment; one parallel line is provided with a normally closed manual valve, and the other three are each provided with a remote manual valve. Since line 1 has a postaccident safety function, namely, containment spray, automatic isolation of this line is not appropriate, and the use of remote manual valves inside containment is acceptable.

Outside containment, line 1 branches into main parallel lines, which have check valves, and into several smaller branch lines. With respect to the isolation valves outside containment, GDC 56 specifies that simple check valves are not suitable automatic isolation valves. However, the staff has determined that the use of a simple check valve outside containment is acceptable for the reasons stated in Section 4.23.3.

A further consideration with respect to line 1 is that several instrument, test connection, and branch lines connect to this line, downstream (containment side) of the specified containment isolation valves outside containment. Valves on these connections are normally closed.

The staff has reviewed the isolation provisions for this penetration and its associated branch lines and has determined that there is reasonable assurance that isolation will be provided if needed. Therefore, the staff finds these valving arrangements acceptable if appropriate administrative controls and/or physical locking devices are provided to ensure these connections are locked closed during operation.

In a letter dated October 4, 1985, the licensee noted that a program has been implemented to verify that normally closed valves are indeed closed. Procedures S01-12.3-43, "Containment Integrity." and S01-12.3-34 "Containment Sphere Safety-Related Alignment," provide assurance that valves are closed and provide for a monthly surveillance of valve alignments.

Line 2 (refueling water return line) branches into four lines inside containment, namely, two recirculation lines from the containment sphere sump, a bypass line from the containment sphere spray header, and the reactor refueling cavity drain line. The latter two lines are isolated from the refueling water return line during reactor operating modes 1 through 4, with single, or two series, closed local manual valves. Under accident conditions, the safety function of the refueling water return line is to recirculate the sump water for the recirculation mode of emergency core cooling and containment spray. Since there is only a single line penetrating containment, and because of its safety function, containment isolation valves, per se, are not provided outside containment. If necessary, however, there are manual valves that can be closed to isolate the containment. A further consideration is that the associated systems are engineered safety features and become extensions of the containment boundary; consequently, they constitute an appropriate isolation barrier. The amount of leakage from the piping and components outside containment is limited by the Technical Specifications; the system piping is periodically pressurized to check for leakage. Therefore, the staff finds this design meets GDC 56 on some other defined basis and considers this issue to be resolved.

4.23.7.2 Main Steamlines

Lines 54 and 55 are the main steamlines; each line is provided with a main steam isolation valve that is manually operated. These valves do not satisfy the requirements of GDC 57; however, the turbine stop valves and turbine control valves are available to automatically or remote manually isolate the main steamlines. However, upstream of the turbine stop valves and turbine control valves are numerous branch lines that also would have to satisfy the requirements of GDC 57. The staff has reviewed the isolation provisions for these branch lines and found their isolation arrangements meet the requirements of GDC 57, with the exception of (1) 1-in. lines to the flash evaporator/air ejector and (2) several 3/4-in. lines to the drain traps. The staff's concern with respect to these lines was the use of normally open local manual valves as isolation valves. As discussed in a July 28, 1986, submittal, the licensee will develop procedures to isolate main steam branch lines and drain lines by November 14, 1986. The staff finds this commitment acceptable.

The main concern in a PWR is for a steamline break that induces a hydraulic transient rupturing steam generator tubes resulting in a radiological release and uncontrolled LOCA outside containment. This scenario would only happen if the pipe were to fail between the steam isolation valve and the stop valve. The failure probability of the steamline is this particular section is low. The evaluation of the radiological consequences of this scenario (see Topic XV-17) has been performed assuming that the steam generator has not been isolated, and the staff found that the consequences were within acceptance criteria. The staff concludes that no modification to the steamlines is warranted; however, the staff recommends that appropriate procedures be developed to isolate these lines when required.

4.23.8 Spare Penetrations

During the topic review adequate information regarding the isolation and leakage testing of the following spare penetrations was not available.

Line	Penetration
Spare penetration	64 through 72

As noted in the June 28, 1983, letter from the licensee, these penetrations are sealed with blind flanges and the penetration design includes provisions for leakage testing. The staff considers this issue resolved.

4.23.9 Air Locks and Hatches

During the topic review adequate detailed information was not available regarding the appropriateness of isolation provisions for piping or instrument lines that may penetrate either the personnel air lock, emergency escape lock, or equipment access hatch.

The licensee has since indicated that the only penetrations are in the external wall of the air locks. These penetrations are for test purposes. Each has at least one closed manual isolation valve under administrative control. On the basis of this information, the staff finds the provisions for isolation acceptable and considers this issue resolved.

4.24 Topic VI-7.B, Engineered Safety Feature Switchover From Injection to Recirculation Mode (Automatic Emergency Core Cooling System Realignment)

10 CFR 50 (GDC 35), as implemented by Item 19 of SRP Section 6.3 requires, in part, that the complete sequence of emergency core cooling system (ECCS)

operation from injection to long-term core cooling (recirculation) should be examined to ensure that minimal manual action is required, and that where manual action is needed, sufficient time is available for the operator to respond. The current procedures at San Onofre Unit 1 for switchover from injection to recirculation require a large number of operator actions during a short timeframe. Further, as discussed below, the instrumentation provided would not be adequate for an assumed worst-case single failure. Failure to terminate injection flow from the refueling water storage tank (RWST) at the correct time could damage the charging and refueling water pumps so that they could not be used for long-term post-LOCA cooling.

RWST level is monitored by a pneumatic indication channel and by a level switch alarm. This design does not satisfy BTP ICSB 20 (IEEE Std. 279) because of reliance on a single alarm to alert the operator to the need to initiate switchover.

The switchover from injection to recirculation modes is a two-part process. At the 21% level in the RWST, the operator should terminate the flow from the main feedwater/safety injection (FW/SI) pumps. At the 12% level, suction from the sump should be established by the operator. When the RWST level drops to 7%, it should no longer be used as the water supply because of net positive suction head/vortex suppression concerns.

Because of the large flow rate from the feedwater pumps, the available time for the operator to perform the switchover is sensitive to the time at which the FW/SI pumps are tripped. If the pumps are not tripped at the 21% level, the level will drop to 7% in approximately 2 min.

In a January 19, 1984, submittal, the licensee proposed to raise the setpoint for termination of FW/SI flow to 30% tank level and the setpoint for recirculation to 21%. This change would provide more time to complete the switchover. Sump level instruments are also available and could be used to determine when actions should be taken. The only alarm provided is the level alarm (currently at 21%) on the RWST.

The results of the limited PRA showed that the present switchover design has a medium risk significance. However, because of the short time periods involved, the staff is concerned that the human error contribution may be high; thus, this issue could have a high risk importance.

The results of the limited PRA showed that installation of redundant RWST indicators would reduce the risk by a factor of 7, by reducing the contribution to risk from failure of the RWST level indicator. For the case of a fully automated switchover mechanism, a total reduction of a factor of 40 is calculated based on eliminating the human error contribution. This analysis assumes the failure probability of the automatic switchover to be negligible. However, a fully automatic switchover also creates the possibility of an inadvertent switchover occurring before there is sufficient water in the sump.

The critical aspect in the process is the termination of injection flow at the proper time. If this is done, there is time for the remaining actions to be completed manually. Therefore, the staff recommends that an automatic feature be installed to terminate the FW/SI flow on low RWST level (either at the present 21% level or at a 30% level). Furthermore, a backup to the single

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RWST level indicator should be provided for determining when the recirculation phase should begin. Sump level instruments could be used as the backup if the correspondence between RWST level and sump level is established and included in emergency procedures and operator training.

By letter dated October 4, 1985, the licensee committed to provide automatic termination of safety injection flow on low tank level. The engineering design is under development. The modification will be scheduled for implementation in accordance with the licensee's integrated implementation schedule for managing plant backfits. The staff finds this commitment acceptable.

4.25 Topic VI-7.C.2, Failure Mode Analysis (Emergency Core Cooling System)

10 CFR 50 (GDC 35), as implemented by SRP Section 6.3, requires, in part, that the systems provided for emergency core cooling be designed with suitable redundancy in components and features to ensure that system safety functions can be accomplished assuming a single failure.

Reviews of failure modes were initiated in the mid-1970s. Two studies, one in 1976 (letter dated December 21, 1976) and the other in 1977 (letter dated December 20, 1977), were completed. At San Onofre Unit 1, implementation of selected modifications was deferred to the SEP; interim procedures and system changes were installed pending completion of the SEP. These areas are discussed below.

4.25.1 Redundant Valve For Volume Control Tank Isolation

Charging pump suction is normally from the volume control tank (VCT) through MOV/LCV 1100C. Upon a safety injection signal, suction is switched to the refueling water storage tank (RWST). Valve 1100C must close so that hydrogen will not be introduced to the charging pump suction when the VCT empties. Failure of MOV/LCV 1100C to close could damage the charging pumps. In the original design, an automatic transfer switch to transfer to the other power division was included. However, failure of this switch could have resulted in loss of both power sources to the valve so the automatic feature was removed.

A manual transfer capability is provided so that the MOV can be powered from either power train. The valve can also be manually closed. In addition, one of the two charging pumps was removed from the equipment automatically started by the sequencers. This pump would then be available for remote manual use in the recirculation mode even if the operating pump were damaged because of failure of the MOV.

For the limited PRA the following four configurations were considered:

(1) initial design--single valve with auto transfer switch, both charging pumps sequenced

(2) present design--single valve, one pump locked out by sequencer, manual action to start it

(3) proposed long-term design--two valves in series, both pumps sequenced

(4) combination of (2) and (3)--two valves, only one pump automatically sequenced

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The core-melt frequency for these different cases was evaluated (core melt assumed to occur if charging system fails). The results show that the initial configuration, with a core-melt frequency of 1×10^{-6} per year, was of medium significance. Either the present design or the proposed design of two valves reduces this frequency to 1×10^{-9} per year. Case 4 would reduce it still further; however, the event frequency with the existing design (case 2) is so low and is comparable with the proposed design (case 3) that no further modifications are warranted. On the basis of the reliability of the system as currently designed, the staff concludes that no further action is necessary.

4.25.2 Control Power to FCV-1115D, E, and F

Three flow control valves (FCVs) are used to regulate safety injection flow after the initial full-flow injection phase. These valves are air operated; a failure in the air system could prevent proper operation. The proposed modification was to provide a redundant source of air with automatic transfer. In the interim, manual transfer to a nitrogen backup was provided.

The results of the limited PRA showed that for the original configuration (i.e., without nitrogen backup), the risk contribution of failure in the air system is of medium significance. With an alternate source of control power, with manual transfer to the emergency nitrogen supply (the present configuration), the calculated core-melt frequency is 8.8×10^{-7} per year. This is considered to be of low risk significance.

The staff finds this modified configuration acceptable and, thus, no further modifications are warranted. Therefore, the staff considers this issue to be resolved.

4.25.3 Hot-Leg Recirculation

As discussed under Topic IX-4, a flushing flow should be provided during long-term post-LOCA recirculation to prevent boron precipitation. The main hot-leg injection flow path at San Onofre Unit 1 is susceptible to single active failure because there are points where flow passes through a single valve. An alternate injection flow path was developed by the licensee. With the primary path and the alternate path, no single active failure of a component or diesel train could prevent hot-leg recirculation. Therefore, the staff concludes that the system modification is acceptable and considers this issue to be resolved.

4.25.4 Other Modifications

The single-failure studies mentioned above also included evaluations of physical and electrical separation and environmental qualification. The December 20, 1977, study also considered second-order effects, such as flooded equipment shorting the power supply. The following recommendations were generated from those studies:

(1) Relocate air horn above elevation 4 ft, and provide a dripproof cover

(2) Provide power-interrupt devices actuated on safety injection system (SIS) operation, or take other corrective action for pumps, valves, and other equipment that may be submerged during a LOCA and that are connected to power supplies with a post-LOCA function.

(3) Reroute power cables to provide cable separation for several pumps and valves including the charging pumps, safety injection pumps, and component cooling water pumps.

(4) Reroute control cables to provide cable separation for pumps and valves including the charging pumps, feedwater pumps, and salt water cooling pumps.

(5) Arrange vital buses 1, 2, 3, and 4, and the utility bus and associated transfer switches to provide physical separation. Also provide for the physical separation of the input and output cables to those buses.

(6) Provide missile barriers between the two charging pumps, the component cooling water pumps, and the two safety injection pumps, or confirm that the probability of missile impact or the energy of such a missile is sufficiently low. (Resolved under Topic III-4.C.)

(7) Provide missile barriers between the RWST and the safety injection pumps and the refueling water pumps, or confirm that the probability of missile impact or the energy of such a missile is sufficiently low. (Resolved under Topic III-4.C.)

(8) Bypass thermal overload cutout switches for valves MOV 720A and B during SIS conditions. (Resolved in Section 4.15.)

(9) Provide isolation relays for PIC 1111X and PC605X controllers and LS 54 switch contacts.

(10) Provide separation and isolation for the pressurizer level and pressure instrumentation in the control room console.

(11) Provide separation and isolation for the bistable output relays associated with the safety injection actuation signal.

(12) Rewire station lighting system to eliminate presence of both power trains in a transfer switch. Also, separate emergency lighting to provide a connection to each of the dc buses while maintaining circuit independence.

(13) Remove DC1 power from breaker 12C02 on 4,160-V bus 2C and all breakers on 4,160-V bus 18. Isolate the cabling between breaker positions 11C11 on 4,160-V bus 1C and 12C11 on 4,160-V bus 2C.

(14) Align 480-V SWGR3 to the power associated with 4,160-V bus 2C and remove the DC 1 power from the switchgear. Isolate the cabling between breaker 1103 on 480-V SWGR 1 and breaker 1203 on 480-V SWGR 2.

(15) Obtain environmental qualification data, or replace components with qualified units for specified equipment. (Covered by 10 CFR 50.49 Environmental Qualification of Electrical Equipment Program.)

(16) Modify breaker circuitry for circulating air fans A-10, A-11, and A-12 to ensure they are locked out by the sequencer in the event of an SIS, or modify ducting to eliminate possibility of sucking water into fan units.

Some of the above issues generated outside the SEP have been covered under other SEP topics (see notations above) or review programs outside the SEP such as the environmental qualification of electrical equipment. In some cases, other actions, such as the fire protection requirement for installation of a dedicated system for shutdown, with transfer switches, will eliminate the issue. The licensee has committed to evaluate the merits of each unresolved recommendation to determine if modifications are warranted. The staff finds this commitment acceptable. The licensee will submit this evaluation together with recommendations for any necessary modifications by September 30, 1986. The staff will report the status and results of the evaluations for these issues in a supplement to the final IPSAR.

4.26 Topic VI-10.A, Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing

10 CFR 50 (GDC 21), as implemented by Regulatory Guide 1.22 and the Westinghouse Standard Technical Specifications (NUREG-0452), requires, in part, that the reactor protection system be designed to permit periodic testing of its functioning including a capability to test channels independently. 10 CFR 50.55a(h), as implemented by IEEE Std. 279-1971 and IEEE Std. 338-1977, requires that response-time testing be performed on a periodic basis for plants with construction permits issued after January 1, 1971.

During the staff review of this topic, the following issues were identified.

4.26.1 Response-Time Testing of Reactor Protection System

In the San Onofre Unit 1 Technical Specifications, the channel response time from channel trip to deenergization of the scram relay is not tested. However, the reactor trip breakers are tested and the rod drop time is measured and must be within specified limits (in the Technical Specifications). These aspects are also covered by plant procedures. Generic Letter 83-28 also addresses requirements for reactor trip breakers.

Several channels (manual, startup rate, safety injection) are not required by the Technical Specifications to be checked, tested, or calibrated. However, station procedures establish testing requirements for these channels at frequencies consistent with Standard Technical Specification requirements.

The staff performed a limited PRA of this issue for San Onofre Unit 1 to estimate the improvement if response-time testing of the reactor protection system (RPS) were required. The results of this assessment indicated that response-time testing has low safety significance. This occurs because response-time testing is concerned with events on the order of seconds and PRAs have shown that response times of minutes are sufficient, for RPS actuation, to ensure the success of the reactivity control function in time to allow other safety systems to act to prevent core melt. Functional tests, such as those currently performed at San Onofre Unit 1, are sufficient to demonstrate functioning on the order of minutes. Therefore, it is the staff's judgment that response-time testing of the RPS is not required. However, the RPS testing currently covered by plant procedures should be incorporated into the Technical Specifications because of the safety significance of this system. By letter dated March 30, 1984, the

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licensee agreed to propose a Technical Specification change to incorporate channel testing, checking, and calibration requirements currently specified only by procedure. The licensee has agreed to submit a proposed Technical Specification change by November 14, 1986.

4.26.2 Testing of Engineered Safety Features

The Technical Specifications contain requirements for surveillance testing (functional tests) of the engineered safety features. As discussed above, modifications to permit response-time testing are not warranted. However, for the containment spray actuation system channels, no limiting conditions for operation, operability, or surveillance requirements are included in the Technical Specifications. A containment spray actuation signal (CSAS) is generated by a safety injection actuation signal (SIAS) (low pressurizer pressure, high containment pressure or manual) and high-high containment pressure. While the SIAS channels are covered by Technical Specification requirements, the CSAS logic is not. It is the staff's position that such a Technical Specification should be provided. The licensee has agreed to submit proposed Technical Specifications by November 14, 1986.

4.26.3 Testing of Support Systems

The staff in the topic evaluation determined that surveillance requirements are not specified in the Technical Specifications for support systems such as the component cooling water and salt water cooling water system. These systems are normally in operation during all plant modes, although the required loads will vary.

By plant procedures, these systems are included in the inservice testing program. As required in this program, pumps are tested monthly and valves, in general, are stroked quarterly. One train of the component cooling water and salt water cooling systems is normally in operation; the operating train is rotated weekly. Valve alignment check lists are established for these systems, and positions are periodically verified according to station procedures. The frequency of valve position verification is equivalent to that required in the Standard Technical Specifications.

Limiting conditions for operation in the Technical Specifications related to decay heat removal redundancy require the following:

(1) In modes 1 and 2, two component cooling water pumps and two salt water cooling water pumps are required to be operable.

(2) In modes 5 and 6, residual heat removal (RHR) trains are required to be operable. Included in the definition of an RHR train are its associated component cooling and salt water cooling components.

The surveillance requirements include weekly verification of breaker alignment and power availability. These systems are used routinely during plant operation and the surveillance requirements are equivalent to Technical Specification surveillance requirements. For these reasons, the staff concludes that adequate assurance of system operability is provided so that further Technical Specification modifications to establish surveillance requirements are not necessary. The staff considers this issue to be resolved.

4.27 Topic VII-1.A, Isolation of Reactor Protection System From Nonsafety Systems, Including Qualification of Isolation Devices

10 CFR 50.55a(h), through IEEE Std. 279-1971, requires, in part, that safety signals be isolated from nonsafety signals and that no credible failure at the output of an isolation device shall prevent the associated protection system channel from meeting the minimum performance requirements specified in the design basis.

The staff in the topic evaluation concluded that the isolation of the RPS channels does not meet current acceptance criteria. The signals from the high neutron flux level, pressurizer pressure, pressurizer level, startup rate, and steam-to-feedwater-flow mismatch monitoring sensors are not isolated from the process recorders and remote meters. In addition, there is no isolation between the nuclear instrumentation for startup rate and the data logger or between the steam-to-feedwater-flow mismatch system and the Optimac computer, which controls steam generator flow and level.

A limited topic PRA was performed assuming that if any fault occurred in an unisolated recorder or controller, it would fail all the associated sensor channels. This evaluation concluded that failures of the RPS as a result of a lack of isolation did not contribute to the overall RPS failure rate. According to NUREG-0460, the common mode failure of control rods to insert results in a scram failure frequency of about 3×10^{-5} per demand based on actual operating experience. This failure mode will not be reduced by qualified isolation devices. The results of the limited PRA showed that the failure probability of the RPS due to failure combinations that contain unisolated faults in nonsafety systems is about 10^{-9} to 10^{-10}; therefore, this issue was considered to be of low risk significance.

The licensee agreed to evaluate the isolation between the RPS channels to determine if the protection function of these channels is adequate. This evaluation was provided by letter dated March 30, 1984, with supplemental information provided in a letter dated August 21, 1984a. The RPS channels evaluated by the licensee are discussed below.

4.27.1 Remote Meters and Recorders

The staff topic evaluation, forwarded by letter dated September 9, 1981, indicated that there is no isolation between the reactor protection system and remote meters and recorders. As a result, the staff was concerned that a short circuit in the recorders or cables associated with these devices may interfere with the proper functioning of the safety equipment. In addition, the staff was concerned with the consequences of a failure in the recorder transfer switch that might interconnect redundant channels.

In a safety analysis dated March 30, 1984, the licensee stated that reliance was placed on the separation and independence of the redundant safety channels. In a response dated August 21, 1984a, the licensee identified the transfer switch as a Westinghouse W-2. This switch is used extensively in nuclear power plant safety applications and is seismically and environmentally qualified. Its use in this application is acceptable as long as the wiring meets acceptance criteria.

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Appendix R concerns (Topic IX-6) have been resolved by the licensee's commitment to provide new instrumentation and controls at a new remote shutdown panel. Thus, the concern with regard to the effects of wiring failures in the control panels and racks on safe shutdown is being addressed in other reviews.

In the March 30, 1984, letter the licensee also stated that current limiting resistors are used in the recorder circuits. The resultant current caused by a recorder chart drive motor to pen motor short circuit would add or subtract, in the worst case, 25% of the signal from the affected circuit. This may inhibit the protective action of that channel but will not propogate to other channels. In addition, voltage feedback to the nuclear instrumentation is unlikely because of the all-plastic casing for the meters and the passive design; that is, no external power is needed because the meter movement is driven directly by the analog signal. Accordingly, this issue is resolved.

4.27.2 Data Logger

The staff SER forwarded by letter dated February 10, 1983, noted that the data logger is not isolated from the nuclear instrumentation system. The licensee's response dated March 30, 1984, indicated that a 91,000-ohm resistor network between the data logger and the nuclear instrumentation provides sufficient isolation. The resultant current represents approximately a 5% change in signal level and approaches the worst-case error expected in such instrumentation. The licensee also argues that the staff PRA shows that failure of such isolation schemes has little (1×10^{-10} per reactor-year) effect on core-melt probability.

The staff has concluded that improving the nuclear instrumentation does not provide a significant improvement in the reliability of the system and is, therefore, not warranted. The staff considers this issue to be resolved.

4.27.3 Feedwater Control

The staff SER also noted that there is no isolation between the steam-to-feedwater flow mismatch channels and the feedwater controls. The licensee has presented arguments for accepting this design that are similar to those that were made in the case of the remote meters and recorders (i.e., redundancy of channels, same quality standards).

As a result of a recent event at the plant, it was determined that there was a component (steam pressure compensator) whose failure could affect all three channels as well as the feedwater control system. Actions to correct this single-failure vulnerability are being implemented independent of the SEP. With these corrective actions, the staff concludes that no further actions as part of the SEP on this issue are required.

4.28 Topic VII-3, Systems Required for Safe Shutdown

4.28.1 Component Cooling Water Surge Tank Level and Instrumentation

10 CFR 50 (GDC 13), as implemented by SRP Section 7.4, Regulatory Guide 1.53, and IEEE Std. 279-1971, requires that the instrumentation necessary for reaching and maintaining cold shutdown conditions meet the single-failure criterion.

The component cooling water (CCW) surge tank level is measured by a single transmitter with indication and alarms provided in the control room. This does not satisfy Section 4.20 of IEEE Std. 279-1971. A local sight gauge is provided on the tank, which is checked once per shift.

The surge tank level is an important parameter because it gives an anticipatory indication of possible CCW loss of water, which could lead to loss of the system function. Failure of the existing single sensor in the "high" condition could give an erroneous and misleading indication to the operator if the surge tank level was low. The operator might not detect a low CCW surge tank level under this condition in sufficient time to correct a problem in the CCW system. Failure of the CCW system could affect the ability to shut down the plant. It is noted, however, that the plant can be maintained in a hot standby condition, removing decay heat through the steam generators, without reliance on the CCW system.

The limited PRA found this issue to be of low risk significance relative to frequency of initiation of small LOCAs from reactor coolant pump seal failures. Since (1) the plant can be safely maintained at hot shutdown for a time sufficient to repair the failed CCW system, (2) the surge tank level can be read locally, and (3) the risk significance of this issue is low, the staff concludes that no backfitting is necessary. This issue is considered to be resolved.

4.28.2 Adequate Seismic Category I Water Supply for the Auxiliary Feedwater System

10 CFR 50 (GDC 2 and 34), as implemented by SRP Section 5.4.7, BTP RSB 5-1, and Regulatory Guide 1.139, requires, in part, that the seismic Category I water supply for auxiliary feedwater have sufficient inventory to permit operation at hot shutdown for 4 hours followed by cooldown to conditions permitting initiation of residual heat removal. The inventory is based on the cooldown time assuming a single active failure and the availability of only onsite or only offsite power.

During the topic review, the staff concluded that sufficient safety-grade water was not maintained in a seismically qualified tank(s) to perform this function.

The licensee has since installed a new tank of condensate water for auxiliary feedwater which is seismic Category I. The tank capacity is 240,000 gal. In Amendment 82, issued on October 24, 1984, the staff approved Technical Specifications for the revised auxiliary feedwater system design including surveillance requirements for the new tank (150,000 gal required for operability). This volume is sufficient to perform a cooldown in accordance with BTP RSB 5-1. The staff finds this acceptable and therefore considers this issue resolved.

4.28.3 TMI Task Action Plan Item II.E.1.1, "Auxiliary Feedwater System Evaluation"

10 CFR 50 (GDC 2 and 34), as implemented by SRP Section 10.4.9, requires, in part, that the auxiliary feedwater system be capable of performing its safety functions when required.

The staff in the topic evaluation noted that a single (passive) failure of the common suction line from the condensate storage tank to the auxiliary feedwater pumps could disable the auxiliary feedwater system. Also, as part of the

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Bulletins and Orders Task Force response to the Three Mile Island (TMI) event, the reliability of auxiliary feedwater at all plants was reevaluated and recommendations for corrective actions developed. These recommendations were incorporated into TMI Item II.E.1.1.

Recommendation GL-2 of TMI Task Action Plan Item II.E.1.1 recommended that licensees install a redundant flow path (piping and valves) for auxiliary feedwater (AFW) supply. As part of the seismic upgrades, redundant parallel suction paths from the new AFW storage tank have been installed. The corresponding Technical Specifications have been issued as discussed in Section 4.28.2.

Recommendation GL-4 of Item II.E.1.1 relates to unprotected normal AFW supply and the need to provide some means of protection. The new AFW storage tank is seismically qualified. Tornado protection is being evaluated as discussed in Section 4.8.

To satisfy Recommendation GL-5, the licensee proposed to install a third AFW pump, which would be electrically powered. The pump was installed during the Cycle 9 outage with power from the new dedicated diesel generator. The pump could be manually initiated to provide auxiliary feedwater if needed. During the subsequent refueling outage, the third AFW pump will be fully upgraded as a safety-grade system.

Two other aspects of Item II.E.1.1 were referred to the SEP integrated assessment for resolution. These items are:

(1) The AFW system should be reevaluated with respect to internally and externally generated missiles, pipe whip, jet impingement, quality and seismic design requirements, and the effects of earthquakes, tornados and floods.

    These concerns are addressed in the context of the resolution of various SEP topic reviews: Topic III-1 (quality), Topic III-2 (wind and tornados), Topics III-5.A/B (pipe break), Topic III-6 (seismic), and so forth.

(2) The San Onofre Unit 1 design does not have the capability to automatically terminate AFW flow to a depressurized steam generator and provide flow to an intact steam generator in the event of a steam- or feedwater-line break. In fact, for some breaks, all three steam generators will be depressurized.

    As part of the topic review for Topics XV-2 (steamline break) and XV-6 (feedwater-line break), the San Onofre Unit 1 design of the main steam and AFW system was evaluated. Operator action is assumed to control AFW flow. Therefore, this issue is covered under these topic reviews.

4.29 Topic VIII-1.A, Potential Equipment Failures Associated With Degraded Grid Voltage

10 CFR 50 (GDC 17) requires an onsite and offsite electric power system to provide functioning of systems and components important to safety. The purpose of this topic is to ensure that a degradation of the offsite power system will not result in the loss of capability of redundant safety-related equipment and to determine the susceptibility of such equipment to the interaction of onsite and offsite emergency power sources.

4.29.1 Degraded Grid Voltage

The topic of degraded grid voltage is being evaluated generically through Multiplant Action (MPA) B-23, "Degraded Grid Voltage Protection for Class 1E Power Systems." The purpose of MPA B-23 is to determine the grid characteristics and to provide a suitable system to isolate the plant from the grid in the event of grid voltage degradation.

The staff's SER for MPA B-23 for San Onofre Unit 1 was forwarded to the licensee by letter dated June 23, 1982. In that letter, the staff found the licensee-proposed modifications and Technical Specification changes acceptable. These modifications consisted of replacing the existing relays with coincidence logic and corresponding Technical Specifications for limiting conditions for operation and surveillance requirements. The schedule for implementation will be determined in accordance with the licensee's integrated implementation schedule.

4.29.2 Adequacy of Station Electrical Distribution Voltages

The adequacy of the station electrial distribution system to operate Class 1E loads within equipment voltage ratings under adverse conditions is being evaluated generically under MPA B-48, "Adequacy of Station Electrical Distribution Voltages."

The staff's SER for MPA B-48 for San Onofre Unit 1 was issued by letter dated July 29, 1983. The licensee committed to perform a study to determine the optimized tap settings for the auxiliary transformer. The tap settings were modified before plant restart. The licensee in a letter dated December 20, 1984, submitted the study results. A voltage monitoring program to verify the results of the analysis was conducted, and the results were submitted on December 4, 1985, as supplemented on June 19, 1986. This analysis and the results of the program are being evaluated by the staff and will be discussed in a supplement to the final IPSAR.

4.30 Topic VIII-3.B, DC Power System Bus Voltage Monitoring and Annunciation

10 CFR 50.55a(h), as implemented by IEEE Std. 279-1971, and 10 CFR 50 (GDC 2, 4, 5, 17, 18, and 19), as implemented by SRP Section 8.3.2, Regulatory Guides 1.6, 1.32, 1.47, 1.75, 1.118, and 1.29, and BTP ICSB-21, require, in part, that the control room operator be given timely indication of the status of the batteries and their availability under accident conditions.

To ensure the design adequacy of the dc power system battery and bus voltage monitoring and annunciation schemes so that the operator can (1) prevent the loss of an emergency dc bus or (2) take timely corrective action in the event of loss of an emergency dc bus.

IEEE Std. 279-1971, Section 4.20, requires that the "system shall be designed to provide the operator with accurate, complete, and timely information pertinent to its own status and to generating station safety. The design shall minimize the development of conditions which would cause meters, annunciators, recorders, alarms, etc. to give anomalous indications confusing to the operator." GDC 17 requires that an onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems and components important to safety.

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The staff reviewed the dc power system battery, battery charger, and bus voltage monitoring and annunciation design with respect to dc power system operability status indication to the operator. More specifically, in the topic evaluation, the staff had proposed that, as a minimum, the following indications and alarms should be provided in the control room for the dc power systems:

(1) battery current (ammeter - charge/discharge)
(2) battery discharge rate high alarm
(3) battery breaker or fuse open alarm
(4) dc bus voltage (voltmeter)
(5) dc bus undervoltage/overvoltage alarm
(6) dc bus ground alarm (for ungrounded systems)
(7) battery charger output current (ammeter)
(8) battery charger breaker or fuse open alarm

At San Onofre Unit 1, the dc power systems consist of 125-V dc systems Nos. 1 and 2 and the uninterruptible power supply (UPS) for safety injection valve MOV 850C. The staff in the topic evaluation concluded that there was no indication of battery current, charger current, dc bus voltage, or breaker/fuse status in the control room.

The limited PRA performed for this topic assumed that with the present design, unannunciated faults are not detected until battery tests are performed each refueling outage. With the additional annunciators, it was assumed that only half of the battery faults are assumed to be detected. Under these assumptions, it was concluded that the unavailability of a 125-V dc bus could be reduced by a factor of 4. Because of the arrangement of dc power supplies at San Onofre Unit 1 in which both dc buses can be powered either from a battery or from either diesel generator, this issue was considered to be of medium risk significance. For the UPS, the risk significance is negligible because it affects only one valve in the safety injection system and the risk significance of that valve failure is dominated by mechanical failures.

In a letter dated March 30, 1984, the licensee responded to the staff SER with an analysis of the existing instrumentation. In Table 2 of that discussion, the licensee noted that indication of breaker/fuse status is provided in the control room and a low voltage alarm is also provided in the control room. In addition, the licensee has stated that the alarms available in the control room when used in conjunction with local instrumentation and periodic testing provide a suitable alternative to providing additional instrumentation.

Past staff practice has been to require a battery current monitor. However, research by Yankee Atomic Electric Company (letter dated April 13, 1983, on SEP Topic VIII-3.B) indicates that a suitable sensitive current monitor is not commercially available. Currently available equipment that has the required range of current (from trickle charge to peak rated discharge) does not have the accuracy and precision necessary. The use of multiple instruments requires a switching system that could introduce a potential high resistance failure that is more probable (because of operator error) than the current design presents.

Other methods to verify the battery is connected to the bus are the use of breaker and fuse status alarms or battery voltage monitoring and, to ensure

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that a high resistance does not develop because of corrosion or metal creep, a periodic inspection program.

The licensee has detailed an acceptable inspection program, which is included in the plant Technical Specifications. The use of control room alarms to call the operators' attention to local battery meters is an acceptable alternative to providing additional monitoring in the control room.

Accordingly, the staff has concluded that no modifications are warranted and that this topic has been resolved.

4.31 Topic VIII-4, Electrical Penetrations of Reactor Containment

10 CFR 50 (GDC 50), as implemented by Regulatory Guide 1.63 and IEEE Std. 317-1972, requires, in part, that penetrations be designed so that the containment structure can accommodate, without exceeding the design leakage rate, the calculated pressure, temperature, and other environmental conditions resulting from any loss-of-coolant accident (LOCA).

As a result of its review, the staff has concluded that with a LOCA environment inside containment, the low voltage ac and dc penetrations do not comply with IEEE Std. 317-1972, Paragraphs 4.2.4 and 4.2.5, and Regulatory Guide 1.63, Paragraph C1, regardless of the initial assumed temperature, because the operating time of the backup circuit breaker is excessive. Excessive time delay in the backup circuit breaker could allow fault currents to exist longer, which could cause excessive heating and consequent damage to the containment penetrations. Under this condition, the integrity of the containment could be compromised.

Consequently, low voltage ac penetration and dc penetration seal design temperatures would be exceeded in the event of a LOCA and failure of the primary protective circuit breaker. The seal outside containment is at a lower temperature than the seal inside, which is exposed to the LOCA environment. The penetration assemblies are checked for pressure integrity monthly and are subject to leak testing.

As discussed in the licensee's October 4, 1985, submittal, some of the low-voltage penetrations were replaced during the Cycle 9 refueling outage as part of the equipment qualification program.

The limited PRA showed that the failure probability of containment integrity as a result of failure of low voltage electrical penetrations is several orders of magnitude smaller than other contributors to containment failure. Thus, this issue is rated low from a risk point of view. On the basis of monthly penetration assembly testing, the staff concludes that modifications to the penetrations are not warranted. The staff considers this issue to be resolved.

4.32 Topic IX-3, Station Service and Cooling Water Systems

10 CFR 50 (GDC 44, 45, and 46), as implemented by SRP Sections 9.2.1 and 9.2.2, requires that a cooling water system be provided, inspected, and tested and that the system be capable of transferring heat from structures, systems, and components important to safety to the ultimate heat sink. The staff in the

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topic evaluation concluded that the design of the service and cooling water system is adequate, except for the following.

4.32.1 Component Cooling Water System Temperature Design Limits

During the review of this topic, the licensee by letter dated November 2, 1981, provided the results of an analysis that indicated that the temperature at the component cooling water (CCW) heat exchanger could reach 227°F. This is 27F° more than the design temperature of 200°F. Therefore, the staff requested that the licensee either (1) demonstrate that this design temperature exceedance would not result in damage to the CCW system or the equipment it serves or (2) provide corrective measures.

In a response dated January 19, 1984, the licensee quantified the conservatisms of the earlier analysis and estimated that the CCW system would not exceed design conditions with a more realistic analysis. The licensee performed scoping calculations to evaluate the heat removal capability of the CCW system considering various equipment configurations as part of the evaluation of Topic V-10.B (see staff SER forwarded by letter dated November 12, 1982). On the basis of these calculations, the staff determined that the CCW system is adequately designed to remove energy from the primary coolant system and other supporting components without exceeding design conditions.

Therefore, the staff agrees with the licensee's assessment and concludes that no additional action is required. This issue is resolved.

4.32.2 Independence of Component Cooling Water System Valves CV-737A and CV-737B

During the review of this topic, the staff found that sufficient information was not available to verify the full independence, (i.e., physical separation, power supplies, and interlocks) of valves CV-737A and CV-737B.

In a January 19, 1984, response, the licensee referenced a report, "Separation and LOCA Environment Assessment of San Onofre Unit 1 Emergency Core Cooling Systems," that had been forwarded by letter dated December 20, 1977, which documents that the independence of valves CV-737A and CV-737B, including routing of controls and power supplies and physical separation. The licensee stated that the independence is acceptable on the basis of the review criteria of Regulatory Guide 1.75. The staff finds this information sufficient to resolve this issue.

4.32.3 Component Cooling Water System Passive Failure

Although the pumps and heat exchangers of the CCW system are redundant, they are connected to single-pipe headers for supply and return whose failure could disable the system.

The component cooling water system is seismically qualified. In addition, the capability exists for reaching cold shutdown using the steam generators with a water-to-water heat exchange. This method was developed as part of the fire protection review (see Section 4.34).

A limited PRA was performed for this issue. The results indicated that with all the conservative assumptions related to passive failures, their contribution to the total failure of the CCW system is about 6%. This contribution is judged to be insignificant with respect to the overall risk.

On the basis of the seismic qualification of the system, the alternative heat removal capability, and the overall low risk of this event, the staff considers this issue resolved.

4.32.4 Salt Water Cooling System Supply Water Failure

Although the SWC pumps and the heat exchangers are redundant, the supply of cooling water is taken from a common area, the intake bay. The intake bay area water supply is subject to disruption if either the tsunami gate or motor-operated valves fail closed.

The auxiliary SWC pump can also be used to provide cooling water to the CCW heat exchanger. This pump is located in a separate pit, and its supply of cooling water is drawn from outside the tsunami gate and motor-operated valves. Also, the licensee, as discussed above (see Section 4.32.3), has the capability for reaching cold shutdown using the steam generators.

A limited PRA was performed for this issue. The results indicated that the risk associated with this valve-failure event is low. However, the results were based on valve-failure data for a valve design, which the staff found was not sufficiently representative of the actual installation; therefore, the staff concluded that this issue may be of greater importance than indicated in the limited PRA.

The tsunami gates were originally installed to provide the ability to isolate the plant from the high water level generated by the tsunami. Since 1967, many changes have been made in the site flood control features, such as the north channel drainage ditch. When other concerns related to the tsunami gates arose, under SEP Topic II-3.B.1, concerning how long the gates should be closed, warning time, where cooling water would be discharged, and other concerns, the benefits of closing the tsunami gates were reevaluated. As discussed in the licensee's May 7, 1984, submittal and in the staff's August 27, 1984a, SER, the runup through the intake and connected passages would not be high enough to result in flooding of the plant yard. The licensee, therefore, has removed the gates. This action will ensure that tsunami valve failure will not contribute to SWC unavailability. On the basis of the above licensee actions, the staff considers this issue resolved.

4.32.5 Independence of Salt Water Cooling System Components

During the review of this topic, the staff found that sufficient information was not available to verify the full independence (i.e., physical separation, power supplies, and interlocks) of valves POV5, POV6, MOV220A, and MOV720B.

In a January 19, 1984, response the licensee referenced a report, "Separation and LOCA Environment Assessment of San Onofre Unit 1 Emergency Core Cooling Systems," that had been forwarded by letter dated December 20, 1977, which addresses the physical and electrical separation of control and power cables for these valves. As discussed under Topic VI-7.C.2, the results of the above analysis are being evaluated to determine if modifications are required. This item will be covered by that review. Because this item will be incorporated and resolved in a related topic, this item is considered complete.

4.32.6 Loss of Salt Water Cooling Pump Bearings Flush

The SWC pump bearings are flushed by the service water supply system, which is not a safety-grade system. Thus, the possibility exists that this flushing function could be lost when the demand for the SWC system would be greatest.

The licensee has since contacted the SWC pump supplier and found that these pumps can withstand a loss of bearing water for up to 30 consecutive days with the need of minimal operator actions. Therefore, adequate time would exist to take corrective action for this event.

On the basis of this information, the staff considers this issue resolved.

4.32.7 Salt Water Cooling System Reliability

The SWC system is a two-train system; one train is normally in operation with the other in standby. The second pump starts automatically on low discharge pressure. Each pump is aligned to deliver flow to one of the two CCW heat exchangers. The air-operated discharge valves are interlocked with the corresponding CCW heat exchanger inlet valves. However, no check valves were installed in the pump discharge lines; thus, reverse flow through the line could have resulted in reverse rotation of the pump. The auxiliary SWC water pump and the two screen wash pumps can be connected by valve operations to provide SWC flow.

This system design historically has had reliability problems. The most severe case occurred in March 1980 when both of the SWC pumps as well as the auxiliary SWC pump became unavailable as a result of three separate failures (pump shaft break, failure of air-operated valve to open because of dessicant contamination, and loss of prime to the auxiliary SWC pump). Recurrent problems have also been experienced with the air operators and pressure switch for the discharge valves. Table 4.2 summarizes the past history of the SWC system failures.

To correct some of these problems, the licensee has installed check valves in the two discharge lines. The automatically controlled air-operated valve operators have been removed; the valves are now manually operated valves, which are maintained in the locked-open position. Thus, system reliability will be enhanced.

The licensee has also implemented design changes to eliminate the problem areas such as the discharge lines' valve configuration. The staff believes that these modifications will improve SWC system reliability. However, as recently as October 1984, system reliability was affected by operator error. Thus, the staff recommends that the licensee perform a formal reliability evaluation of the SWC system to determine whether any additional improvements are appropriate. The licensee committed to submit the results of the evaluation by August 31, 1986.

4.33 Topic IX-5, Ventilation Systems

10 CFR 50 (GDC 5, 19, 60, and 61), as implemented by SRP Sections 9.4.1, 9.4.2, 9.4.3, 9.4.4, and 9.4.5, requires, in part, that ventilation systems be provided and have the capability to provide a safe environment for plant personnel and

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for the operation of engineered safety features. The staff in the topic evaluation found the ventilation systems acceptable, except for the following items.

4.33.1 Reactor Auxiliary Building

The reactor auxiliary building ventilation systems' single air supply unit is vulnerable to a single active failure of either the unit itself or the differential pressure switch. The staff in its topic evaluation recommended that the licensee should either demonstrate that ventilation for the charging pumps is unnecessary or propose a corrective action.

A limited PRA was performed for this issue. The results indicated that the probability of a ventilation system failure that fails the charging pumps, in combination with other system failures required to result in a core-melt sequence, is small in comparison with the expected total core-melt frequency. This issue was, therefore, rated to be of low risk significance.

The licensee, by letter dated June 24, 1983, provided the results of an evaluation of this issue. On the basis of this evaluation, the licensee found that even if the single supply fan failed, the air exhaust fans of the containment sphere purging and exhaust system are of sufficient size to maintain adequate ventilation of the charging pumps.

On the basis of the low risk significance and containment ventilation availability, the staff concludes that no modifications are warranted and considers this issue resolved.

4.33.2 Switchgear and Cable Spreading and 480-V Switchgear Rooms

The switchgear and cable spreading room and 480-V switchgear room ventilation systems are vulnerable to a single active failure. The staff in the topic evaluation recommended that the licensee either demonstrate that ventilation of the equipment serviced by these systems is unnecesary or propose a corrective action.

A limited PRA was performed for this issue. The results indicated that a loss of ventilation in the switchgear and cable spreading room could affect both the normal and emergency trains of the ac power system. A ventilation failure-induced loss of the equipment in this room combined with a failure of the turbine-driven auxiliary feedwater pump portion of the auxiliary feedwater system would eliminate the standard means of removing heat from the core. Since the frequency of this combination of events is relatively high, comparable to the core-melt frequency for a PWR, this issue was rated to be of high risk significance.

The results of a limited PRA rated the risk associated with the loss of the 480-V switchgear room ventilation system as low. The basis of this conclusion was the assumption that the loss of this system would result in the loss of only one of the two ac power trains. The availability of the redundant ac power supply and the auxiliary feedwater system, both unaffected by the loss of ventilation in the 480-V switchgear room, reduces the significance of this event to a point where it would not significantly affect the core-melt frequency.

As discussed in the licensee's June 24, 1983, letter, new room ventilation systems were recently installed. Modifications in these areas to resolve Appendix R (10 CFR 50) fire protection concerns necessitated installation of these systems. The new systems consist of an air conditioning unit with backup supply and exhaust fans. However, the systems are neither safety grade nor powered from the emergency diesel generators. Therefore, the licensee in an August 21, 1984, letter provided the results of a room-temperature analysis for periods during both normal operating and postaccident conditions when room ventilation could be lost. On the basis of these results, the licensee has determined that the room air ambient temperature would not exceed 104°F, the normal qualification temperature for most industrial equipment, if room doors are opened and room lights are extinguished in a timely manner after loss of ventilation. To ensure that these actions will be performed in a timely manner if required, the licensee committed to implement a room temperature monitoring program.

By letter dated January 17, 1986, the licensee submitted the procedures for room temperature monitoring and for corrective actions if the ventilation systems are lost. The corrective actions include using the backup fans, opening the room doors, and reducing room lighting. If temperatures cannot be controlled, the equipment in the room is considered inoperable and a plant shutdown is initiated. The staff considers these actions acceptable to resolve this issue.

4.33.3 Administration Building (Battery Room and Inverter Room)

The staff in the topic evaluation concluded that the administration building ventilation system is susceptible to disabling single failures. The control room, located in this building, has a separate ventilation system. During the topic evaluation the licensee was requested to either demonstrate that ventilation of the equipment in the battery and inverter rooms is unnecessary or propose a corrective action.

The results of a limited PRA rated the risk associated with the loss of the administration building ventilation system as high. The basis of this conclusion was the assumption that the failure of one of the station batteries as a result of a loss of ventilation could have a significant effect on the core-melt frequency. Failure of the ventilation system, that is, failure of a single fan, can be expected to occur more frequently than the loss of a dc power train as a result of battery faults. Battery faults generally are significant contributors to dominant accident sequences.

By letter dated June 24, 1983, the licensee noted that loss of ventilation in the battery room would not adversely affect equipment as a result of the small amount of heat generated by the batteries and their high heat capacity. The main concern for battery room ventilation is hydrogen buildup. Generally, this would be due to a high rate of charging. There is a vent in the battery room roof as well as hydrogen monitors, which alarm in the control room. In response to the alarm, the operator ensures that adequate ventilation is established and removes the battery from the equalizing charge.

By letter dated August 21, 1984, the licensee provided the results of a thermal analysis performed for the inverter room. The results of this analysis showed that the room air ambient temperature would not exceed 104°F even if a loss of room ventilation were to occur under normal operating or postaccident conditions. For most industrial equipment 104°F is the normal qualification temperature.

On the basis of the above information, the staff concludes that this issue is resolved.

4.34 Topic IX-6, Fire Protection

10 CFR 50 (Sections III.G and III.L of Appendix R) requires that fire protection features be provided for structures, systems, and components important to safe shutdown and that if separation and barriers between redundant safe shutdown equipment in a fire area do not meet the requirements of Section III.G.2, alternative or dedicated shutdown capability should be provided that can achieve safe shutdown conditions independent of the effects of fire in the area.

A remote shutdown panel, providing process instrumentation and controls, has been installed. Other plant modifications and procedures were also implemented to satisfy the fire protection requirements. A capability is provided to use the steam generators to bring the plant to cold shutdown if other systems, such as the residual heat removal system, are affected by the fire.

By letter dated April 24, 1984, the licensee submitted a proposal to install a dedicated safe shutdown system consisting of a new diesel generator (non-safety-related) and associated switchgear, transfer switches, and the like. The dedicated system, to be used for safe shutdown in the event of a fire in the plant, was installed during the Cycle 9 outage. The staff's safety evaluation report was issued on May 15, 1986. This topic is, therefore, considered complete.

4.35 Topic XV-1, Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

10 CFR 50.34 requires that each applicant for a construction permit or operating license provide an analysis and evaluation of the design and performance of structures, systems and components of the facility with the objective of assessing the risk to public health and safety resulting from operation of the facility, including determination of the margins of safety during normal operations and transient conditions anticipated during the life of the facility. 10 CFR 50 (GDC 10 and 15), as implemented by SRP Sections 15.1.1 through 15.1.4, requires, in part, that plants be adequately designed to mitigate the consequences of feedwater system malfunctions that result in an increase in feedwater flow.

An increase-in-feedwater-flow event will be terminated when a safety injection signal is generated, since the main feedwater pumps are automatically realigned to provide emergency core cooling. As discussed in the topic evaluation, the concern is that the steam generator may be overfilled before the safety injection signal is actuated and that a main steamline break may result from the weight of water in the line. The cooldown associated with such a break could be more severe than that for the design-basis steamline break (more water initially available for blowdown).

The licensee has committed to evaluate this event to determine whether corrective measures are necessary to prevent violation of design limits. The staff finds this commitment acceptable. The licensee committed to provide this evaluation and to identify any necessary modifications by November 14, 1986.

4.36 Topic XV-2, Spectrum of Steam System Piping Failures Inside and Outside Containment (PWR)

10 CFR 50 (GDC 17, 21, and 35), as implemented by SRP Section 15.1.5, requires, in part, that the most severe single active component failure should be assumed and the effect of loss of offsite power should be considered in an analysis of a spectrum of steamline breaks.

Following a main steamline break, the main feedwater system will be realigned to the safety injection mode and the turbine-driven train of auxiliary feedwater will have no source of steam. This will leave only the motor-driven train of auxiliary feedwater to remove decay heat unless main feedwater can be restored. Therefore, a postulated single failure of the motor-driven AFW pump would remove all means of feedwater addition to the steam generators for decay heat removal. The emergency procedures specify that the main feedwater system should be realigned to the feedwater addition mode once safety injection is terminated. The shutoff head of the feedwater pumps is approximately 1,020 psig. Therefore, after the initial depressurization, when reactor pressure returns to above 1,200 psig, the feedwater pumps are not needed for safety injection and can be used for feedwater addition. If secondary system decay heat removal cannot be restored, primary feed and bleed would be necessary. Although analyses of feed-and-bleed capability have been done, this is an untested method.

As previously discussed (Section 4.28.3), the licensee has committed to provide a third train of auxiliary feedwater (motor-driven). This design change will eliminate the concern regarding a single failure of the motor-driven auxiliary feedwater pump.

The limited PRA determined that with the proposed hardware changes and with the above-described emergency procedures, risk to the public as a result of steamline breaks at San Onofre Unit 1 is low. The staff concludes that the proposed action is sufficient to resolve this issue.

Table 4.1 Integrated assessment summary

SEP Topic No.	IPSAR Section No.	Title	Tech. Spec. changes required	Modification or analysis requirements	Licensee agrees	Completion date	PRA results
II-1.C	4.1	Potential Hazards or Changes in Potential Hazards Due to Transportation, Institutional, and Military Facilities					
	4.1.1	Overpressure From Explosions	No	None	Yes	--	--
	4.1.2	Frequency of Shipments	No	None	Yes	--	--
	4.1.3	Toxic Gases	No	Identify planned modifications for the control room ventilation system.	Yes	Submitted	--
II-3.A, II-3.B, II-3.B.1, II-3.C	4.2	Hydrologic Description; Flooding Potential and Protection Requirements; Capability of Operating Plants To Cope With Design-Basis Flooding Conditions; Safety-Related Water Supply (Ultimate Heat Sink)	No	See Topic III-3.A.	Yes	--	--
II-4.F	4.3	Settlement of Foundations and Buried Equipment	No	See Topic III-6.	Yes	--	--
III-1	4.4	Classification of Structures, Components, and Systems (Seismic and Quality)	No	Perform analyses discussed in Sections 4.4.1 through 4.4.7, or alternatively evaluate the safety significance of the component and show that it is adequately monitored by a formal inspection program or that failure is of no consequence on the basis of safety function.	Yes	10 CFR 50.71 (e)(3)(ii)	--

Table 4.1 (Continued)

SEP Topic No.	IPSAR Section No.	Title	Tech. Spec. changes required	Modification or analysis requirements	Licensee agrees	Completion date	PRA results
III-2	4.5	Wind and Tornado Loadings	No	Perform cost-benefit analysis of upgrading for different windspeeds. See Topics III-4.A and III-7.B.	Yes	Submitted	--
III-3.A	4.6	Effects of High Water Level on Structures					
	4.6.1	Groundwater	No	Evaluate short-term hydrostatic load at grade; justify lower water level if necessary.	Yes	Submitted	--
	4.6.2	Roof Loadings	No	Demonstrate roofs can withstand ponding load, or propose corrective measures. (Integrate Topic II-3.B.1.)	Yes	Submitted	--
III-3.C	4.7	Inservice Inspection of Water Control Structures	No	Revise inspection program in accordance with staff comments.	Yes	Before next inspection	--
III-4.A	4.8	Tornado Missiles	No	Identify modifications necessary to provide safe shutdown path that is protected from tornado missiles. (Integrate Topic III-2.)	Yes	Submitted	--
III-5.A	4.9	Effects of Pipe Break on Structures, Systems, and Components Inside Containment	--	Perform fracture mechanics analyses, systems analyses. Determine leak detection system sensitivity. (Integrate Topic V-5.)	Yes	1/30/87	--
III-5.B	4.10	Pipe Break Outside Containment	--	Perform fracture mechanics analyses, systems analyses.	Yes	1/30/87	--
III-6	4.11	Seismic Design Considerations	No	Complete analysis of remaining safety-related piping and equipment and implement necessary modifications.	Yes	Complete	--

Table 4.1 (Continued)

SEP Topic No.	IPSAR Section No.	Title	Tech. Spec. changes required	Modification or analysis requirements	Licensee agrees	Completion date	PRA results
III-7.B	4.12	Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria					
	4.12.1	Design Codes, Criteria, and Load Combinations	No	Confirm that seismic loads dominate tornado loads and that correct combinations were used. (Integrate Topics II-3.B.1, II-4.F, III-2, III-5.A, III-5.B, and III-6 for structural upgrade.)	Yes	--	--
	4.12.2	Load Combinations for Reactor Containment	No	Evaluate potential for buckling.	Yes	Submitted	--
III-7.D	4.13	Containment Structural Integrity Tests	No	None	Yes	--	--
III-8.A	4.14	Loose-Parts Monitoring and Core Barrel Vibration Monitoring	No	None	Yes	--	Low
III-10.A	4.15	Thermal-Overload Protection for Motors of Motor-Operated Valves	No	None	Yes	--	Low
III-10.B	4.16	Pump Flywheel Integrity	No	None	Yes	--	--
IV-2	4.17	Reactivity Control Systems, Including Functional Design and Protection Against Single Failures	No	None	Yes	--	Low
V-5	4.18	Reactor Coolant Pressure Boundary (RCPB) Leakage Detection					

Table 4.1 (Continued)

SEP Topic No.	IPSAR Section No.	Title	Tech. Spec. changes required	Modification or analysis requirements	Licensee agrees	Completion date	PRA results
V-5	4.18.1	Leakage Into Containment					
	4.18.1.1	System Sensitivity	No	See Topic III-5.A.	Yes	--	--
	4.18.1.2	Operability Requirements	Yes	Provide Technical Specifications (TS) for surveillance of leak detection systems. (Integrate Topic III-5.A.)	Yes	11/14/86	--
	4.18.1.3	Seismic Qualification	No	Provide procedures or qualify one leak detection system.	Yes	11/14/86	--
	4.18.1.4	Testability	No	None	Yes	--	--
	4.18.2	Intersystem Leakage	No	None	Yes	--	--
V-10.A	4.19	Residual Heat Removal System Heat Exchanger Tube Failures					
	4.19.1	Radiation Monitoring	No	None	Yes	--	Low
V-10.A	4.19.2	Sampling	No	None	Yes	--	--
	4.19.3	Testing of Recirculation Heat Exchanger	No	None	Yes	--	--
V-11.A	4.20	Requirements for Isolation of High- and Low-Pressure Systems					
	4.20.1	Chemical and Volume Control System					
	4.20.1.1	Charging Pump Discharge Valves	No	None	Yes	--	Low
	4.20.1.2	Letdown Piping	No	None	Yes	--	--

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Table 4.1 (Continued)

SEP Topic No.	IPSAR Section No.	Title	Tech. Spec. changes required	Modification or analysis requirements	Licensee agrees	Completion date	PRA results
V-11.A	4.20.2	Safety Injection System	No	None	Yes	--	Medium
	4.20.3	Long-Term Recirculation System	No	None	Yes	--	Low
V-11.B	4.21	Residual Heat Removal System Interlock Requirements					
	4.21.1	Residual Heat Removal System Interlocks	No	None	Yes	--	Low
	4.21.2	Overpressurization Protection of Residual Heat Removal System	Yes	Provide TS for operability of overpressure protection system when residual heat removal system is in operation.	Yes	11/14/86	--
VI-1	4.22	Organic Materials and Post-accident Chemistry	No	Institute periodic inspection program.	Yes	--	--
VI-4	4.23	Containment Isolation System					
	4.23.1	Electrical Aspects					
VI-4	4.23.1.1	Purge Lines	Yes	None	Yes	--	--
	4.23.1.2	Key Control and Control Panel Access Procedures for Sequencer Doors	No	Provide procedures for control panel access.	Yes	Complete	--
	4.23.1.3	Redesign of Block SIAS Annunciator Window	No	None	Yes	--	--
	4.23.1.4	Automatic Loading of Diesel Generator Radiator Fans	No	Revise procedures for operator action to restore diesel generator cooling on loss of offsite power.	Yes	Complete	--

Table 4.1 (Continued)

SEP Topic No.	IPSAR Section No.	Title	Tech. Spec. changes required	Modification or analysis requirements	Licensee agrees	Completion date	PRA results
VI-4	4.23.1.5	Override Capability for Reactor Coolant Sample Line Isolation Valves	No	Resolved in Section 4.23.2.	Yes	--	--
	4.23.2	Valve Actuation	No	None	Yes	--	Low
	4.23.3	Valve Type	No	None	Yes	--	Low
	4.23.4	Valve Location	No	Seismically qualify lines. See Topic III-6.	Yes	Complete	Low
	4.23.5	Isolation of Closed Systems	No	Seismically qualify lines. See Topic III-6.	Yes	Complete	Low
				Develop procedures to identify when component cooling water valves need to be closed.	Yes	11/14/86	Low
	4.23.6	Isolation of Air Handling Unit Cooling Lines	No	Seismically qualify lines. See Topic III-6.	Yes	Complete	Low
	4.23.7	Isolation of Branch Lines					
	4.23.7.1	Refueling Water Lines	No	Provide administrative procedures and/or locking devices for supply line.	Yes	Complete	Low
				Evaluate when to close valves in return line and modify procedures as needed.	Yes	11/14/86	Low
	4.23.7.2	Main Steamlines	No	Provide procedures for isolation of lines following steam generator tube rupture.	Yes	11/14/86	Low
	4.23.8	Spare Penetrations	No	None	Yes	--	Low

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Table 4.1 (Continued)

SEP Topic No.	IPSAR Section No.	Title	Tech. Spec. changes required	Modification or analysis requirements	Licensee agrees	Completion date	PRA results
VI-4	4.23.9	Air Locks and Hatches	No	None	Yes	--	--
VI-7.B	4.24	Engineered Safety Feature Switchover From Injection to Recirculation Mode (Automatic Emergency Core Cooling System Realignment)	No	Provide automatic termination of injection and a backup to the single refueling water storage tank level indicator; review procedures and training.	Yes	--	Medium
VI-7.C.2	4.25	Failure Mode Analysis (Emergency Core Cooling System)					
	4.25.1	Redundant Valve for Volume Control Tank Isolation	No	None	Yes	--	Low
	4.25.2	Control Power to FCV-1115D, E, and F	No	None	Yes	--	Low
	4.25.3	Hot-Leg Recirculation	No	None	Yes	--	--
	4.25.4	Other Modifications	No	Evaluate benefits of incorporating recommended modifications.	Yes	9/30/86	--
VI-10.A	4.26	Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing					
	4.26.1	Response-Time Testing of Reactor Protection System	Yes	Include testing now in procedures in TS.	Yes	11/14/86	Low
	4.26.2	Testing of Engineered Safety Features	Yes	Include test for containment spray actuation in TS.	Yes	11/14/86	Low
	4.26.3	Testing of Support Systems	No	None	Yes	--	--

Table 4.1 (Continued)

SEP Topic No.	IPSAR Section No.	Title	Tech. Spec. changes required	Modification or analysis requirements	Licensee agrees	Completion date	PRA results
VII-1.A	4.27	Isolation of Reactor Protection System From Nonsafety Systems, Including Qualification of Isolation Devices					
	4.27.1	Remote Meters and Recorders	No	None	Yes	--	Low
	4.27.2	Data Logger	No	None	Yes	--	Low
	4.27.3	Feedwater Control	No	None as part of SEP (see Section 4.27.3)	Yes	--	Low
VII-3	4.28	Systems Required for Safe Shutdown					
	4.28.1	Component Cooling Water Surge Tank Level and Instrumentation	No	None	Yes	--	Low
	4.28.2	Adequate Seismic Category I Water Supply for the Auxiliary Feedwater System	Yes	None	Yes	--	--
	4.28.3	TMI Task Action Plan Item II.E.1.1, "Auxiliary Feedwater System Evaluation"	Yes	Integrated into Topics III-1, III-2, III-4.A, III-5.A, III-5.B, III-6, VIII-3, and XV-2.	Yes	Cycle 10	--
VIII-1.A	4.29	Potential Equipment Failures Associated With Degraded Grid Voltage					
	4.29.1	Degraded Grid Voltage	Yes	Implement modifications and TS for coincident logic undervoltage protection.	Yes	--	--
	4.29.2	Adequacy of Station Electrical Distribution Voltage	No	Perform voltage monitoring program for transformer tap settings.	Yes	Submitted	--

Table 4.1 (Continued)

SEP Topic No.	IPSAR Section No.	Title	Tech. Spec. changes required	Modification or analysis requirements	Licensee agrees	Completion date	PRA results
VIII-3.B	4.30	DC Power System Bus Voltage Monitoring and Annunciation	No	None	Yes	--	Medium
VIII-4	4.31	Electrical Penetrations of Reactor Containment	No	None	Yes	--	Low
IX-3	4.32	Station Service and Cooling Water Systems					
	4.32.1	Component Cooling Water System Temperature Design Limits	No	None	Yes	--	--
	4.32.2	Independence of Component Cooling Water System Valves CV-737A and CV-737B	No	None	Yes	--	--
	4.32.3	Component Cooling Water System Passive Failure	No	Install dedicated shutdown system. (Integrated with Appendix R requirements.)	Yes	Complete	Low
	4.32.4	Salt Water Cooling System Supply Water Failure	No	None	Yes	--	Low
	4.32.5	Independence of Salt Water Cooling System Components	No	See Topic VI-7.C.2.	Yes	--	--
	4.32.6	Loss of Salt Water Cooling Pump Bearings Flush	No	None	Yes	--	--
	4.32.7	Salt Water Cooling System Reliability	No	Perform a reliability evaluation of salt water cooling system to determine appropriate modifications.	Yes	8/31/86	--
IX-5	4.33	Ventilation Systems					
	4.33.1	Reactor Auxiliary Building	No	None	Yes	--	Low

Table 4.1 (Continued)

SEP Topic No.	IPSAR Section No.	Title	Tech. Spec. changes required	Modification or analysis requirements	Licensee agrees	Completion date	PRA results
IX-5	4.33.2	Switchgear and Cable Spreading and 480-V Switchgear Rooms	No	Implement temperature-monitoring program and procedures.	Yes	Complete	High/Low
	4.33.3	Administration Building (Battery and Inverter Room)	No	None	Yes	--	High
IX-6	4.34	Fire Protection	Yes	Provide dedicated diesel generator, switchgear, and transfer switches.	Yes	Complete	--
XV-1	4.35	Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in System Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve	No	Reanalyze to show that consequences are acceptable, or propose corrective measures.	Yes	11/14/86	--
XV-2	4.36	Spectrum of Steam System Piping Failures Inside and Outside Containment (PWR)	Yes	Install additional train of motor-driven auxiliary feedwater.	Yes	Partial in Cycle 9 outage; complete during Cycle 10 outage	Low

Table 4.2 Salt water cooling (SWC) system reliability problems

Event date	Description of event	Reference
November 1, 1967	A tsunami gate inadvertently closed because of a shorted limit switch that became submerged; switch was relocated.	67-13 (see Appendix F)
February 9, 1968	During operation of stop gate (gate was being moved for switch relocation (see above)), accumulator reservoir tank ruptured. A rupture diaphragm and enlarged relief valve were installed.	68-04 (see Appendix F)
October 9, 1969	A tsunami gate fell down into the intake structure when bond between the gate and attachment plate studs failed. No disruption in flow occurred. Attachment design was improved.	69-08 (see Appendix F)
March 1975	Shaft of north SWC pump sheared because of fatigue from excessive vibration resulting from worn shaft bearings.	July 24, 1980, letter
January 16, 1978	A SWC pump breaker tripped open when the other pump was out for maintenance.	Licensee Event Report (LER) 78-01 (see Appendix F)
March 10, 1980	Total loss of saltwater cooling - shaft of south SWC pump sheared (excessive vibration from worn bearings), air-operated valve on the north pump discharge failed closed (desiccant contamination of solenoid "O" ring), and auxiliary SWC pump did not function because of inadequate priming (air leak into suction line). The screen wash pumps were used to provide cooling until SWC flow was restored.	LER 80-06; AEOD report dated August 12, 1982 (attached to Topic IX-3 SER); NUREG-0900, Vol. 3, No. 3 (Abnormal Occurrence 80-7)
July 7, 1980	South train air-operated discharge valve (POV-6) failed to open because of burnt-out solenoid valve; wrong solenoid had been installed during maintenance overhaul (ac installed, dc required).	LER 80-031

Table 4.2 .(Continued)

Event date	Description of event	Reference
July 28, 1980	POV-6 failed to open automatically, but could be manually opened. After above event, ac coil was replaced with a dc coil; however, it was determined that the spring force was too strong for dc coil to overcome. A new dc solenoid valve was installed to correct the problem.	LER 80-031
June 9, 1981	SWC discharge of the component cooling water (CCW) heat exchanger was partially blocked resulting in low flow and malfunction of butterfly valve; cause was a buildup of gooseneck barnacles. A long shutdown had prevented heat treatment.	LER 81-009
January 18, 1982	POV-6 failed to open on demand until the plant operator adjusted manual control of solenoid valve.	IE Inspection Report 82-04
February 1, 1982	An air-operated discharge valve only closed halfway when its pump was deenergized.	IE Inspection Report 82-10
February 8, 1982	While south train was being placed in service, pump developed normal discharge pressure, but the discharge valve shut approximately 3 sec after pump start (three attempts). The cause was failed pressure switch.	LER 82-007
March 19, 1982	POV-5 failed to open.	IE Inspection Report 82-10
May 13, 1982	South SWC pump was removed from its pedestal for maintenance. Water entered intake area from the hole. The water rose to within 2 in. of the elevation of north SWC pump motor vents. North pump was secured when pump amperage and discharge valve cycled erratically. After water was pumped out and north pump restarted, discharge valve failed shut because of residual moisture in the pressure switch and melted insulation in a relay. Procedures did not provide adequate precautions with regard to tide level.	LER 82-015; NUREG-0090, Vol. 5, No. 2 (Abnormal Occurrence 80-7) update

Table 4.2 (Continued)

Event date	Description of event	Reference
August 13, 1982	With north pump in operation, POV-6, the other discharge valve, opened unexpectedly; reverse flow through the idle pump resulted; waterhammer and reduction in SWC system flow also occurred. Cause was a misaligned manual operator on POV solenoid control valve.	LER 82-024, IE Inspection Report 82-32
August 19, 1982	With south pump out for maintenance, north pump had to be secured because of degraded motor bearing; salt water intrusion from a packing leak was the cause. Motor was replaced.	LER 82-022
October 13, 1982	POV-6 malfunctioned because of pressure switch problem.	IE Inspection Report 82-32
October 29, 1982	POV-6 malfunctioned because of operator error.	IE Inspection Report 82-32, monthly operating report for October 1982
December 16, 1982	Auxiliary SWC pump failed to develop required discharge pressure during operability test; after drain trap union was tightened, it was restored to operability.	Monthly operating report for December 1982
March 16, 1983	Worker drilling concrete for rebar installation drilled into air line supplying SWC pump discharge valves. South discharge valve (pump was running) remained open; north discharge valve remained closed. Air line had been field-run and was embedded in concrete; its exact location was not shown on available drawings.	PNO-V-83-14, AEOD Report No. AEOD/T333 (October 31, 1983)
October 10, 1984	SWC flow was aligned to upper CCW heat exchanger (HX) while residual heat removal flow was aligned to the lower CCW HX; therefore, no heat transfer to SWC occurred. Cause was inadequate plant status information; configuration was off normal because lower HX, which is usually in use when north SWC pump is placed in service, as had just been done, was out of service.	LER 84-12

5 REFERENCES

Code of Federal Regulations, Title 10, "Energy" (includes General Design Criteria).

Letter, December 21, 1976, from K. Baskin (SCE) to A. Schwencer (NRC), Subject: Single Failure Analysis.

---, December 20, 1977, from K. Baskin (SCE) to A. Schwencer (NRC), Subject: Single Failure Analysis.

---, July 24, 1980, from J. Haynes (SCE) to D. Crutchfield (NRC), Subject: Failure of Saltwater Cooling System.

---, January 7, 1981, from D. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic V-10.A.

---, April 27, 1981, from D. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic II-2.A, "Severe Weather Phenomena."

---, August 3, 1981, from D. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic V-11.A.

---, September 9, 1981, from D. Crutchfield (NRC) to R. Dietch (SCE), Subject: Draft Safety Evaluation for SEP Topic VII-1.A.

---, November 2, 1981, from W. Moody (SCE) to D. Crutchfield (NRC), Subject: Topic Assessment for SEP Topic IX-3.

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---, February 17, 1982, from D. Crutchfield (NRC) to R. Dietch (SCE), Subject: Status of Generic Item B-24.

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APPENDIX A

TOPIC DEFINITIONS FOR SEP REVIEW*

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*The topic definitions and other data appearing in this appendix were assembled in April 1977; therefore, some references to organizations and other references reflect the status of the review at that time. The basis for deletion of a topic because the review of a related TMI task, USI, or other SEP topic was identical to the review of the SEP topic was developed in May 1981 on a generic basis and does not address the plant-specific design aspects. The plant-specific deletions that are due to generic review or nonapplicability to the San Onofre Unit 1 design are given in Appendices B and C.

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TOPIC: II-1.A Exclusion Area Authority and Control

(1) Definition:

The establishment of the exclusion area and the licensee's control over it are reviewed at the construction permit/operating license stage. Thereafter, the licensees are required to report any changes with safety implications. The concern exists, however, that (1) the original review may not have been as thorough as currently done, or (2) changes may have occurred but have not been reported and reviewed. In particular, new activities within the exclusion area (for example, new recreational facilities or offshore oil drilling) and topographical changes (for example, changes in water levels) may need to be reviewed.

(2) Safety Objective:

To assure that appropriate exclusion area authority and control is maintained by the licensee.

(3) Status:

Selective reviews have been performed (San Onofre Nuclear Generating Station Unit 1) or are under way (Fort Calhoun) where changes in exclusion area boundary have become necessary.

(4) References:

1. Title 10, "Energy," Code of Federal Regulations, Part 100*
2. NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants - LWR Edition, "December 1975,"** Section 2.1.2

TOPIC: II-1.B Population Distribution

(1) Definition:

Population distribution in the vicinity of operating plants may have changed since the initial review was performed at the construction permit stage. Special attention should be given to new housing and commercial, military, or institutional installations established since the initial population-distribution review.

(2) Safety Objective:

New population distributions may require revision of low-population zone (LPZ) and population center to assure appropriate protection for the public by complying with the guidelines of 10 CFR Part 100. Adjustments may have

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*Hereafter referred to as 10 CFR.
**Hereafter referred to as Standard Review Plan.

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to be made in emergency plans. New accident analyses may have to be performed to determine consequent conformance with 10 CFR Part 100 at new LPZ distances. Potential need for additional engineered safety features (for example, chemical sprays or better filters) exists.

(3) Status:

Has been done on a selective basis only, that is, Pilgrim Unit 1 new population center.

(4) References:

1. 10 CFR Part 100
2. Standard Review Plan, Section 2.1.3

TOPIC: II-1.C Potential Hazards or Changes in Potential Hazards Due to Transportation, Institutional, Industrial, and Military Facilities

(1) Definition:

For operating plants there are three concerns:

(a) New hazards created since the facility was licensed,

(b) Hazards considered for licensing but that have expanded beyond projections or which were not reviewed against current criteria, and

(c) Hazards that were not analyzed at the licensing stage because of lack of regulatory criteria at the time.

Nearby transportation, institutional, industrial, and military facilities may be threats to safe plant operation due to:

(a) Control room infiltration of toxic gases,

(b) Onsite fires triggered by transport of combustible chemicals from offsite releases,

(c) Shock waves due to detonation of stored or transported explosives and military ordnance firing, and

(d) Onsite aircraft impact.

(2) Safety Objective:

To assure that the control room is habitable at all times and that the postulated hazards will not result in releases in excess of the 10 CFR Part 100 guidelines by disabling systems required for safe plant shutdown.

(3) Status:

Action has been taken on a selective basis only, for example, curbing of military air activity in the vicinity of the Big Rock Point Plant. Liquid

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natural gas (LNG) hazards at Calvert Cliffs are under review. The review of older plants did not consider offsite hazards in detail (for example, aircraft traffic in the vicinity).

(4) Reference:

Standard Review Plan, Sections 2.2.1 and 2.2.2

TOPIC: II-2.A Severe Weather Phenomena

(1) Definition:

Safety-related structures, systems, and components should be designed to function under all severe weather conditions to which they may be exposed. Meteorological phenomena to be considered include tornadoes, snow and ice loads, extreme maximum and minimum temperatures, lightning, combinations of meteorology and air-quality conditions contributing to high corrosion rates, and effects of sand and dust storms.

(2) Safety Objective:

To assure that the designs of safety-related structures, systems, and components reflect consideration of appropriate extreme meteorological conditions and severe weather phenomena. This effort would identify deficiencies in designs and/or operation that may contribute to accidental releases of radioactivity to the atmosphere resulting in doses to the public in excess of 10 CFR Part 100 or Part 20 guidelines (as appropriate to the design of the component or system).

(3) Status:

Generic studies have been initiated to develop guidelines for extreme temperatures and lightning, and to the review the current Branch Positions on snow loads. Estimated completion dates are 6/1/78 or later.

(4) References:

1. 10 CFR Part 100 or Part 20
2. Regulatory Guide 1.76, "Design Basis Tornado for Nuclear Power Plants"
3. Standard Review Plan, Section 2.3.1
4. Branch Technical Position, "Winter Precipitation Loads," March 24, 1975
5. Inquiry by Chairman Rowden Concerning Lightning Protection, July 9, 1976
6. 10 CFR Part 50

TOPIC: II-2.B Onsite Meteorological Measurements Program

(1) Definition:

To review the onsite meteorological measurements program to determine the extent that the licensee complies with 10 CFR Part 50, Appendix E and Appendix I.

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(2) Safety Objective:

To assure that adequate meteorological instrumentation to quantify the offsite exposures from routine releases is available and maintained.

(3) Status:

Onsite meteorological measurements programs are being reviewed as a part of the Appendix I evaluations.

(4) References:

1. 10 CFR Part 50, Appendix E and Appendix I
2. Regulatory Guide 1.97, Rev. 1, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident"
3. Regulatory Guide 1.23, "Onsite Meteorological Programs"
4. Standard Review Plan, Section 2.3.3

(5) Basis for Deletion (Related TMI Task, Unresolved Safety Issue (USI), or Other SEP Topic):

(a) TMI Action Plan Task II.F.3, "Instrumentation for Monitoring Accident Conditions" (NUREG-0660)

Task II.F.3 requires that appropriate instrumentation be provided for accident monitoring with expanded ranges and a source term that considers a damaged core capable of surviving the accident environment in which it is located for the length of time its function is required. Regulatory Guide 1.97, Revision 2, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident," issued December 1980, contains the required meteorological instrumentation to quantify the offsite exposure.

(b) TMI Action Plan Task III.A.1, "Improve Licensee Emergency Preparedness - Short Term" (NUREG-0660)

Task III.A.1 requires the evaluation of 10 CFR Part 50, Appendix E, backfit requirements in accordance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." Backfit requirements include review of the Onsite Meteorological Measurement Program.

The evaluations required by Tasks II.F.3 and III.A.1 are identical to SEP Topic II-2.B; therefore, this SEP topic has been deleted.

TOPIC: II-2.C Atmospheric Transport and Diffusion Characteristics for Accident Analysis

(1) Definition:

To review the atmospheric transport and diffusion characteristics assumed to demonstrate compliance with the 10 CFR 100 guidelines with respect to plant design, control room habitability, and doses to the public during and following a postulated design-basis accident. This effort would examine the assumptions for:

(a) Effects of explosive concentrations from onsite or offsite releases of hazardous material for consideration in structural design,

(b) Calculation of relative concentration (x/Q) values for releases of radioactivity and toxic chemicals for consideration in control room habitability, and

(c) Calculations of doses to the public resulting from releases of radioactivity to the atmosphere during and following a postulated design-basis accident.

This effort is considered necessary because most original reviews were performed using the assumptions provided in Regulatory Guides 1.3 and 1.4 which have been found to be generally nonconservative based on evaluation of over 50 sites with actual meteorological observations.

(2) Safety Objective:

To assure that the atmospheric transport and diffusion characteristics originally assumed to demonstrate compliance with the 10 CFR 100 guidelines are appropriate, considering additional onsite meteorological data and results of recent atmospheric diffusion experiments.

(3) Status:

A review of long-term (annual average) atmospheric transport and diffusion characteristics is ongoing for Appendix I evaluations independent of the SEP effort. A study has also recently been performed by the Hydrology-Meteorology Branch for the Division of Operating Reactors for review of the meteorological assumptions for estimating control room dose consequences resulting from post-LOCA purges through tall stacks.

(4) References:

1. 10 CFR Part 20
2. 10 CFR Part 50, Appendix A and Appendix I
3. 10 CFR Part 100
4. Regulatory Guides
   1.3, "Assumption Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors"
   1.4, "Assumptions Used for Evaluating the Potential Radiologcal Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors"
5. Standard Review Plan, Sections 2.3.4, 6.4, 2.2.1, 2.2.2, and 2.2.3

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TOPIC: II-2.D Availability of Meteorological Data in the Control Room

(1) Definition:

Data from the onsite meteorological program should be available in the control room.

(2) Safety Objective:

To assure that the lincensee has appropriate meteorological logical data displayed in the control room to assess conditions during and following an accident to allow for (1) early indication of the need to initiate action necessary to protect portions of the offsite public and (2) an estimate of the magnitude of the hazard from potential or actual accidental releases.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Part 50, Appendix E and Appendix I
2. Regulatory Guide 1.97, Rev. 1, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident"
3. Regulatory Guide 1.23, "Onsite Meteorological Programs"
4. Standard Review Plan, Section 2.3.3

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) TMI Action Plan Task II.F.3, "Instrumentation for Monitoring Accident Conditions" (NUREG-0660)

Task II.F.3 requires that appropriate instrumentation be provided for accident monitoring with expanded ranges and a source term that considers a damaged core capable of surviving the accident environment in which it is located for the length of time its function is required. Regulatory Guide 1.97, Revision 2, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident," issued December 1980, contains the required meteorological instrumentation to quantify the offsite exposure.

(b) TMI Action Plan Task III.A.1, "Improve Licensee Emergency Preparedness - Short Term" (NUREG-0660)

Task III.A.1, "Improve Licensee Emergency Preparedness - Short Term," requires the evaluation of 10 CFR Part 50, Appendix E backfit requirements in accordance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." Backfit requirements include review of the Onsite Meteorological Measurement Program.

(c) TMI Action Plan Task I.D.1, "Control Room Design Reviews" (NUREG-0660)

Task I.D.1, "Control Room Design Reviews," requires that operating reactor licensees and applicants for operating licenses perform a detailed control room design review to identify and correct design deficiencies. This review will include an assessment of control room layout, the adequacy of the information provided, the arrangement and identification of important controls and instrumentation displays, the usefulness of the audio and visual alarm systems, the information recording and recall capability, lighting, and other considerations of human factors that have an impact on operator effectiveness.

The evaluations required by Tasks II.F.3, III.A.1, and I.D.1 are indentical to SEP Topic II-2.D; therefore, this SEP topic has been deleted.

TOPIC: II-3.A Hydrologic Description

(1) Definition:

Hydrologic considerations are the interface of the plant with the hydrosphere, the identification of hydrologic causal mechanisms that may require special plant design or operating limitations with regard to floods and water supply requirements, and the identification of surface- and groundwater uses that may be affected by plant operation.

These hydrologic considerations may have changed since they were reviewed at the licensing stage. A review of such changes, if any, should be performed including an assessment of their impact on the plants.

(2) Safety Objective:

To assure that the designs of safety-related structures, systems, and components reflect consideration of appropriate hydrologic conditions, and to identify deficiencies in designs and/or operations that could contribute to accidental radioactive releases.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Parts 20, 50, and 100
2. American National Standards Institute, ANSI N170-1976, "Standards for Determining Design Basis Flooding at Power Reactor Sites"
3. Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants"
4. Standard Review Plan, Section 2.4.1

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TOPIC: II-3.B Flooding Potential and Protection Requirements

(1) **Definition**:

If the potential for floods exists and protection is required, the type of protection (sand bags, flood doors, bulkheads, and so forth) will be reviewed to assure that equipment is available and that provisions have been made to implement the required protection

(2) **Safety Objective**:

To assure that safety-related structures, systems, and components are adequately protected against floods.

(3) **Status**:

Flooding protection requirements were reviewed on selected operating plants during the winter of 1976 due to the potential for flooding caused by ice accumulation and predictions for abnormally high spring runoff for some areas.

(4) **References**:

1. 10 CFR Parts 50 and 100
2. Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants"
3. American National Standards Institute, ANSI N170-1976, "Standards for Determining Design Basis Flooding at Power Reactor Sites"
4. Standard Review Plan, Section 2.4.10

TOPIC: II-3.B.1 Capability of Operating Plants To Cope With Design-Basis Flooding Conditions

(1) **Definition**:

Protection against postulated floods is accomplished, if necessary, by "hardening" the plant and by implementing appropriate technical specifications and emergency procedures.

These technical specifications and flood emergency procedures need to be reviewed for plants licensed prior to 1972 to establish the degree of conformance with current criteria. Flooding criteria used for the design of older plants are not known.

(2) **Safety Objective**:

Same as II-3.B

(3) **Status**:

Same as II-3.B

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(4) References:

1. 10 CFR Part 100
2. American National Standards Institute, ANSI N170-1976, "Standards for Determining Design Basis Flooding at Power Reactor Sites"
3. Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants"
4. Standard Review Plan, Sections 2.4.3, 2.4.4, 2.4.5, and 2.4.7

TOPIC: II-3.C Safety-Related Water Supply (Ultimate Heat Sink [UHS])

(1) Definition:

To determine the adequacy of onsite water sources with respect to providing safety-related water during emergency shutdown and maintenance of safe shutdown. The location and inventory of safety-related water sources and the meteorological conditions to be used in evaluating both temperature and inventory of the sources should be established. Considerations of ice, low water, leak potential, and underwater dams should be included. In most cases, plants operating prior to 1973 will have to be reviewed to establish the degree of conformance with current criteria. Prior to the issuance of Regulatory Guide 1.27 in 1973, the Standard Format and Content (now Regulatory Guide 1.70) provided the only guidelines to prospective applicants on UHS requirements. Since compliance was not required and hydrologic and meteorologic criteria had not been established, usually only minimal data were provided.

(2) Safety Objective:

To assure an appropriate supply of cooling water during normal and emergency shutdown procedures.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Part 100
2. Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants"
3. Standard Review Plan, Sections 2.4.11 and 9.2.5

TOPIC: II-4 Geology and Seismology

(1) Definition:

Prior to the adoption of Appendix A to 10 CFR Part 100 in 1973, the Standard Format provided the only guidelines to prospective applicants regarding the type of geologic and seismic information needed by the Atomic Energy Commission staff. The applicant, because compliance with Regulatory Guide 1.70 was not required, usually provided only minimal data. Therefore, a re-review of plants licensed prior to 1973 is needed in order to determine the adequacy of the plant design with respect to geologic and seismologic phenomena such as earthquakes, landslides, ground collapse, and liquefaction.

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The review will also include ground motion and surface faulting and will establish the ground-motion values and foundation conditions to be input into the structural reevaluation for seismic loads. (It is possible that some of the older plants would require assessing only the effects of new geologic and seismic discoveries on the site safety and the resulting design acceleration and/or the response spectra.)

(2) Safety Objective:

To assure that accidents (for example, loss-of-coolant accident) do not occur and that plants can safely shut down in the event of geologic and seismologic phenomena which may occur at the site.

(3) Status:

Selected plants are undergoing reevaluation of geology and seismology (San Onofre Nuclear Generating Station Unit 1 and Humboldt Bay). A plan for reevaluating operating plants was developed in 1975-76 but has not been implemented pending formation of the Systematic Evaluation Program.

(4) References:

1. Standard Review Plan, Sections 2.5.1, 2.5.2, 2.5.3, 2.5.4, and 2.5.5
2. 10 CFR Part 100, Appendix A

TOPIC: II-4.A Tectonic Province

(1) Definition:

This subtopic covers a specific area within the major topic Geology and Seismology. Its purpose is to reassess the tectonic province for operating plants based on more current knowledge. (A tectonic province is a region characterized by a relative consistency of the geologic structural features contained within. Tectonic provinces are used operationally as regions within which risk from earthquakes not associated with tectonic structures or faults is considered uniform. Usually the largest historical earthquake not associated with a specific structure can be assumed to occur anywhere within the same province.)

(2) Safety Objective:

To assure that plants can be safely shut down in the event of geologic and seismologic phenomena which may occur at the site.

(3) Status:

The Geosciences Branch is currently attempting to delineate the boundaries of specific tectonic provinces (estimated completion date, fall 1977). The Site Safety Standards Branch is attempting to revise Appendix A to 10 CFR Part 100 so that the definition of tectonic province will more closely conform to its operational use (estimated completion date, 1978). We currently accept such provinces as generally proposed by King, Rogers, or Eardley. Limited subdivision of these provinces has been allowed based on thorough geological and seismic analyses.

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(4) References:

1. 10 CFR Part 100, Appendix A
2. King, P. B., Tectonic Map of North America; Washington, D.C., U.S. Geological Survey, 1969
3. Rogers, John, The Tectonics of the Appalachians, N.Y., Wiley-Interscience, 271 p, 1970
4. Eardley, A. H., "Tectonic Divisions of North America," Bulletin of the American Association of Petroleum Geologists, 35: 2229-2237, 1951

TOPIC: II-4.B Proximity of Capable Tectonic Structures in Plant Vicinity

(1) Definition:

This subtopic covers a specific area within the major topic Geology and Seismology. Its purpose is to determine the expected shaking characteristics at a plant site from known capable faults. The ground motion associated with an earthquake generated by a capable fault or a tectonic structure may be greater than that associated with earthquakes in the same tectonic province not related to the structure.

(2) Safety Objectives:

To assure that plants can be safely shut down in the event of geologic and seismologic phenomena which may occur at the site.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Part 100, Appendix A
2. Standard Review Plan, Section 2.5.2
3. Regulatory Guide 1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants"

TOPIC: II-4.C Historical Seismicity Within 200 Miles of Plant

(1) Definition:

Determination of the safe shutdown earthquake (SSE) is made with consideration of past seismicity in the vicinity of the plant. However, there is sometimes disagreement or inconsistency in reporting older earthquakes in the literature. Current high seismicity may also indicate possible hidden tectonic features.

The historical seismicity within 200 miles of the plants will be reviewed including all earthquakes of Richter magnitude greater than 3.0 or of Modified Mercalli intensity greater than III. Association with tectonic features and provinces should be included.

(2) Safety Objective:

To assure that the SSE is compatible with past seismicity in the area.

(3) Status:

No work currently being done in this subject for operating reactors.

(4) References:

1. Richter, C. F., Elementary Seismology, W. H. Freeman and Company, San Francisco, Calif., 1958
2. 10 CFR Part 100, Appendix A

TOPIC: II-4.D Stability of Slopes

(1) Definition:

Overstressing a slope may cause sudden failure with rapid displacement or shear strain which may damage safety-related structures. The possibility of movement is evaluated by comparing forces resisting failure to those causing failure. An assessment of this ratio should be made to determine the safety factor.

(2) Safety Objective:

To assure that safety-related structures, systems, and components are adequately protected against failure of natural or man-made slopes.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. Standard Review Plan, Section 2.5.5
2. 10 CFR Part 100, Appendix A
3. Naval Facilities Engineering Command, NAVFAC DM-7, "Design Manual - Soil Mechanics, Foundations, and Earth Structures."

TOPIC: II-4.E Dam Integrity

(1) Definition:

Dam integrity is the ability of a dam to safely perform its intended functions. These functions would normally include remaining stable under all conditions of reservoir operation, controlling seepage to prevent excessive uplifting water pressures or erosion of soil materials, and providing sufficient freeboard and outlet capacity to prevent overtopping.

(2) Safety Objective:

To assure that adequate margins of safety are available under all loading conditions and uncontrolled releases of retained liquid are prevented.

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For many projects an important consideration is the necessity of assuring that an adequate quantity of water is available in times of emergency.

(3) Status:

Additional guidance on assuring the integrity of dams is currently being developed by the Office of Standards Development in Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated With Nuclear Power Plants," and through the geotechnical engineering service contract with the U.S. Army Corps of Engineers on design of structures such as ultimate heat sinks.

(4) References:

1. Standard Review Plan, Section 2.5.6
2. 10 CFR Part 100, Appendix A
3. U.S. Army Corps of Engineers, EM 1110-2-1902, "Engineering and Design Stability of Earth and Rock-Fill Dams," Office of Chief of Engineers, 1970
4. U. S. Army Corps of Engineers, EM 1110-2-2300, "Earth and Rock-Filled Dams General Design and Construction Considerations," 1971
5. Regulatory Guide 3.11, "Design, Construction, and Inspection of Embankment Retention Systems for Uranium Mills"

TOPIC: II-4.F Settlement of Foundations and Buried Equipment

(1) Definitions:

Structural loads develop pressures in compressible strata which are not equivalent to the original geostatic pressures. Settlement and differential settlement should be evaluated.

(2) Safety Objective:

To assure that safety-related structures, systems, and components are adequately protected against excessive settlement.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. Standard Review Plan, Section 2.5.4
2. 10 CFR Part 100, Appendix A
3. Naval Facilities Engineering Command, NAVFAC DM-7, "Design Manual - Soil Mechanics, Foundations, and Earth Structures"

TOPIC: III-1 Classification of Structures, Components, and Systems (Seismic and Quality)

(1) Definition:

Plant structures, systems, and components that are required to withstand the effects of a safe shutdown earthquake and remain functional should be

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classified as Seismic Category I. Systems and components important to safety should be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed. Review the classification of structures, systems, and components important to safety to assure they are of the quality level commensurate with their safety function.

(2) Safety Objective:

To assure that structures, systems, and components will fullfill their intended safety functions in accordance with design requirements. To assure that structures, systems, and components necessary for safety will withstand the effects of the designated safe shutdown earthquake and will remain functional.

(3) Status:

There is currently no Division of Operating Reactors activity to confirm the classification of structures, components, and systems important to safety of operating reactors.

(4) References:

1. Standard Review Plan, Section 3.2.1
2. Standard Review Plan, Section 3.2.2
3. Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants"
4. Regulatory Guide 1.29, "Seismic Design Classification"

TOPIC: III-2 Wind and Tornado Loadings

(1) Definition:

Review the capability of the plant structures, systems, and components to withstand design wind loadings in accordance with 10 CFR 50, Appendix A. The review includes the following: (A) Design Wind Protection; (B) Tornado Wind and Pressure Drop Protection; (C) Effect of Failure of Structures Not Designed for Tornado on Safety of Category I Structures, Systems and Components; (D) Tornado Effects on Emergency Cooling Ponds.

(2) Safety Objective:

To assure that Category I structures, systems, and components are adequately designed for tornado winds and pressure drop, that any damage to structures not designed for tornado-generated forces will not endanger Category I structures, systems, and components, and that tornado winds will not prevent the water in the cooling ponds from acting as a heat sink.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A, General Design Criterion (GDC) 2
2. Standard Review Plan, Sections 3.3, 3.8, and 9.2.5
3. Regulatory Guides
   1.76, "Design Basis Tornado for Nuclear Power Plants"
   1.117, "Protection of Nuclear Plants Against Industrial Sabotage"

TOPIC: III-3.A Effects of High Water Level on Structures

(1) Definition:

If the high water level for the plant is reevaluated and found to be above the original design basis, then review the ability of the plant structures to withstand this water level.

(2) Safety Objective:

To provide assurance that floods or high water level will not jeopardize the structural integrity of the plant seismic Category I structures and that seismic Category I systems and components located within these structures will be adequately protected.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 2
2. Standard Review Plan, Sections 2.4, 3.4, and 3.8
3. Regulatory Guides
   1.59, "Design Basis Floods for Nuclear Power Plants"
   1.102, "Flood Protection for Nuclear Power Plants"

TOPIC: III-3.B Structural and Other Consequences (e.g., Flooding of Safety-Related Equipment in Basements) of Failure of Underdrain Systems

(1) Definition:

Some plants rely on underdrain systems to limit the water table elevation at the plant to a safe level. Review underdrain systems of those facilities in which they are used.

(2) Safety Objective:

To assure that the integrity of underdrain systems is maintained because a failure could lead to a rise in water table elevation which, in turn, could jeopardize the integrity of structures or the safety equipment within such structures.

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(3) Status:

The structural consequences of the failure of underdrain systems were thoroughly reviewed during the construction-permit review of Douglas Point Units 1 and 2 and Perry Units 1 and 2. There are no ongoing reviews of this topic for operating facilities.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 2
2. Standard Review Plan, Sections 2.4.13, 3.4, and 3.8

TOPIC: III-3.C Inservice Inspection of Water Control Structures

(1) Definition:

Review the adequacy of the inservice inspection program of water control structures for operating plants to assure conformance with the intent of Regulatory Guide 1.127.

(2) Safety Objective:

To assure that water control structures of a nuclear power facility (for example, dams, reservoirs, and conveyance facilities) are adequately inspected and maintained so as to preclude their deterioration or failure which could result in flooding or in jeopardizing the integrity of the ultimate heat sink for the facility.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) Reference:

Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated With Nuclear Power Plants"

TOPIC: III-4.A Tornado Missiles

(1) Definition:

Plants designed after 1972 have been consistently reviewed for adequate protection against tornadoes. The concern exists, however, that plants reviewed prior to 1972 may not be adequately protected, in particular, those reviewed before 1968 when Atomic Energy Commission criteria on tornado protection were developed.

An assessment of the adequacy of a plant to withstand the impact of tornado missiles would include:

(a) Determination of the capability of the exposed systems, components, and structures to withstand key missiles (including small missiles with penetrating characteristics and larger missiles which result in an overall structural impact),

(b) Determination of whether any areas of the plant require additional protection.

The systems, structures, and components required to be protected because of their importance to safety are identified in Regulatory Guide 1.117.

(2) Safety Objective:

To assure that those structures, systems, and components necessary to ensure:

(a) The integrity of the reactor coolant pressure boundary,

(b) The capability to shut down the reactor and maintain it in a safe shutdown condition, and

(c) The capability to prevent accidents which could result in unacceptable offsite exposures,

can withstand the impact of an appropriate postulated spectrum of tornado-generated missiles.

(3) Status:

The Regulatory Requirements Review Committee (RRRC) has approved case-by-case rereviews of plants against criteria in Regulatory Guide 1.117, which establishes the systems, structures, and components required to be protected against tornado missiles. This rereview was deferred pending the formation of the SEP.

The RRRC is in the process of rereviewing Standard Review Plan, Section 3.5.1.4, which establishes appropriate missiles and impact velocities for new applications.

Electric Power Research Institute (EPRI) has missile research in progress.

(4) References:

1. Standard Review Plan, Section 3.5.1.4
2. Regulatory Guide 1.117, "Tornado Design Classification"

TOPIC: III-4.B Turbine Missiles

(1) Definition:

A number of nonnuclear plants and one nuclear plant (Shippingport) have experienced turbine disk failures. Rancho Seco has had chemistry problems leading to sodium deposits which caused stress-corrosion cracking of disks. Failure of turbine disks and rotors can result in high energy missiles which have the potential for resulting in plant releases in excess of 10 CFR 100 exposure guidelines.

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Two areas of concern should be considered:

(a) Design overspeed failures - material quality of disk and rotor, inservice inspection for flaws, chemistry conditions leading to stress-corrosion cracking, and

(b) Destructive overspeed failures - reliability of electrical overspeed protection system, reliability and testing program for stop and control valves, inservice inspection of valves.

The focus of the review would be on turbine disk integrity and overspeed protection, including stop, intercept, and control valve reliability.

(2) Safety Objective:

To assure that all the structures, systems, and components important to safety (identified in Regulatory Guide 1.117) have adequate protection against potential turbine missiles either by structural barriers or a high degree of assurance that failures at design (120%) or destructive (180%) overspeed will not occur.

(3) Status:

No work currently being done on this subject for operating plants. Electric Power Research Institute (EPRI) has missile research in progress.

(4) References:

1. Regulatory Guides
   1.115, "Protection Against Low Trajectory Turbine Missiles"
   1.117, "Tornado Design Classification"
2. Standard Review Plan, Section 3.5.1.3

TOPIC: III-4.C Internally Generated Missiles

(1) Definition:

Review the probability of missile generation and the extent to which safety-related structures, systems, and components are protected against the effects of potential internally generated missiles (including missiles generated inside or outside the containment).

(2) Safety Objective:

To provide assurance that the integrity of the safety-related structures, systems, and components will not be impaired and that they may be relied on to perform their safety functions following any postulated internally generated missile.

(3) Status:

No work currently being done on this subject for operating plants. Electric Power Research Institute (EPRI) has missile research in progress.

(4) Reference:

Standard Review Plan, Sections 3.5.1.1 and 3.5.1.2

TOPIC: III-4.D Site-Proximity Missiles (Including Aircraft)

(1) Definition:

Review the extent to which safety-related structures, systems, and components are protected against the effects of missiles postulated in Topic II-1.C, including postulated aircraft crashes and resulting fires.

(2) Safety Objective:

To provide assurance that the integrity of the safety-related structures, systems, and components will not be impaired and that they will perform their safety functions in the event of a site-proximity missile.

(3) Status:

No work currently being done on this subject for operating plants. Electric Power Research Institute has missile research in progress.

(4) Reference:

Standard Review Plan, Sections 3.5.1.5, 3.5.1.6, 3.5.2, and 3.5.3

TOPIC: III-5.A Effects of Pipe Break on Structures, Systems, and Components Inside Containment

(1) Definition:

Review the licensee's break and crack location criteria and methods of analysis for evaluating postulated breaks and cracks in high and moderate energy fluid system piping inside containment. The review includes consideration of compartment pressurization, pipe whip, jet impingement, environmental effects, and flooding. Regulatory Guide 1.46 does not require that cracks be postulated inside containment. However, the recent proposed revision to Standard Review Plan, Section 3.6.2, "Determination of Break Locations and Dynamic Effects Associated With the Postulated Rupture of Piping," recommends that cracks be postulated inside containment. Old and current plants are not postulating cracks.

(2) Safety Objective:

To assure that the integrity of structures, systems, and components relied upon for safe reactor shutdown or to mitigate the consequences of a postulated pipe break is maintained.

(3) Status:

This program has not been started for facilities licensed prior to about early 1974. Subsequent to that date, this topic was included in the operating-license review and has been completed for later facilities.

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(4) References:

1. 10 CFR Part 50, Appendix A, GDC 4
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
3. Standard Review Plan, Sections 3.6.2 and 3.8
4. Regulatory Guides
   1.46, "Protection Against Pipe Whip Inside Containment"
   1.29, "Seismic Design Classification"

TOPIC: III-5.B Pipe Break Outside Containment

(1) Definition:

Review the licensee's break and crack location criteria and methods of analysis for evaluating postulated breaks and cracks in high and moderate energy fluid system piping located outside containment. The review includes consideration of compartment pressurization, pipe whip, jet impingement, environmental effects, and flooding.

(2) Safety Objective:

To assure that pipe breaks would not cause the loss of needed functions of safety-related systems, structures, and components and to assure that the plant can be safely shut down in the event of such breaks.

(3) Status:

This task is complete for all operating plants with the exception of three plants for which the review is in progress.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 4
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
3. Standard Review Plan, Section 3.6.1
4. Regulatory Guides
   1.46, "Protection Against Pipe Whip Inside Containment"
   1.29, "Seismic Design Classification"
5. Standard Review Plan, Branch Technical Position MEB 3-1, "Postulated Break and Leakage Locations in Fluid System Piping Outside Containment"
6. NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) Issue 3-25
7. Standard Review Plan, Section 3.6.2

TOPIC: III-6 Seismic Design Considerations

(1) Definition:

Review and evaluate the original plant design criteria in the following areas: Seismic Input, Analysis and Design Criteria, Qualification of Electrical and Mechanical Equipment, Seismic Instrumentation, Seismic

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Categorization, and the effect of failure of non-Category I structures on the safety of Category I structures, systems, and components.

(2) Safety Objective:

To ensure the capability of the plant to withstand the effect of earthquakes.

(3) Status:

Humboldt Bay and San Onofre plants are currently undergoing seismic review. Technical Assistance Contracts:

(a) Seismic Conservatism (Lawrence Livermore Laboratory)
(b) Elasto-Plastic Seismic Analysis (Lawrence Livermore Laboratory)
(c) Seismic Review of Operating Plants (Newmark)

(4) References:

1. Standard Review Plan, Sections 2.5, 3.7, 3.8, 3.9, and 3.10
2. Regulatory Guides
   1.12, "Instrumentation for Earthquakes"
   1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants"
   1.61, "Damping Values for Seismic Design of Nuclear Power Plants"
   1.92, "Combining Modal Responses and Spatial Components in Seismic Response Analysis"
   1.122, "Development of Flood Design Spectra for Seismic Design of Floor-Supported Equipment or Components"

TOPIC: III-7.A Inservice Inspection, Including Prestressed Concrete Containments With Either Grouted or Ungrouted Tendons

(1) Definition:

Review licensee's inspection program for all Category I structures including steel, reinforced concrete, and prestressed concrete containments. The program should include investigations for possible corrosion and cracking of steel containments, excessive cracking of concrete structures, lift-off tests of tendons, periodic testing of prestressing tendons for containments with grouted tendons, and possible deterioration of prestressed containments.

(2) Safety Objective:

To assure that the licensee's inspection program will detect any damaging deterioration of the structures and that they will be capable of performing as required by 10 CFR 50, Appendix A.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

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(4) References:

1. 10 CFR Part 50, Appendix A
2. Standard Review Plan, Section 3.8
3. Regulatory Guides
   1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures"
   1.90, "Inservice Inspection of Prestressed Concrete Containment Structures With Grouted Tendons"

TOPIC: III-7.B Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria

(1) Definition:

Review the design codes, design criteria, and load combinations for all Category I structures (that is, containment, structures inside containment, and structures outside containment).

(2) Safety Objective:

To provide assurance that the plant Category I structures will withstand the NRC specific design conditions without impairment or structural integrity or the performance of required safety functions.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 2 and 4
2. Standard Review Plan, Section 3.8

TOPIC: III-7.C Delamination of Prestressed Concrete Containment Structures

(1) Definition:

Review the design of prestressed concrete containment structures to assess the likelihood of delamination occurring in the shell walls or dome and to evaluate the consequences, if any.

(2) Safety Objective:

To assure that the licensee's design and construction methods have provided a structure which will maintain its integrity and will perform its intended function. Delaminations (internal cracking of concrete in planes roughly parallel to the surface) could possibly reduce the capability of the concrete to withstand compression.

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(3) Status:

This review applies to all plants with prestressed concrete containments. A delamination occurred in the domes of the Turkey Point and Crystal River prestressed concrete containments. No evidence of such occurrences have been reported at other plants; however, no specific inspections have been made for any delaminations. It is not clear if the Structural Integrity Test or the existing inservice inspection programs would discover the existence of any delaminations.

(4) References:

Safety Evaluation Reports for Turkey Point (Docket No. 50-250/251) and Crystal River (Docket No. 50-302)

TOPIC: III-7.D Containment Structural Integrity Tests

(1) Definition:

Review the licensee's structural integrity testing procedure to ensure compliance with the requirements of 10 CFR 50, Appendix A.

(2) Safety Objective:

To assure that the licensee's design and constructive methods provide a structure which will safely perform its intended functions.

(3) Status:

This review applies to all plants. To our knowledge, all containments have had a structural integrity test. This opinion should be verified.

(4) References:

1. 10 CFR Part 50, Appendix A
2. Standard Review Plan, Sections 3.8.1 and 3.8.2

TOPIC: III-8.A Loose-Parts Monitoring and Core Barrel Vibration Monitoring

(1) Definition:

Inservice surveillance programs to detect loose parts and excessive motion of the main core support structure.

(2) Safety Objective:

To detect loose parts or excessive vibration before they can cause flow blockage or mechanical damage to the fuel or other safety-related components.

(3) Status:

The NRC staff currently requires applicants to describe and licensees to implement a loose-part detection program. Guidance for such a program is

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provided in a newly proposed Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors." The regulatory guide outlines the minimum system characteristics which the NRC staff feels are necessary for a workable system and combines this with a technical specification and reporting procedures for a complete and enforceable loose-part detection program.

The concept of detecting core barrel motion through use of excore neutron detectors is well established. A proposed regulatory guide that describes an acceptable core barrel vibration monitoring program has been temporarily placed on "hold" to permit the NRC staff and its consultants (Oak Ridge National Laboratory Inspection and Enforcement Group) time to evaluate apparently anomalous data from core barrel motion monitoring programs that are currently in service as part of the technical specification requirements for certain licensees.

(4) References:

1. Combustion Engineering, CE Report CEN-5(P), "Palisades Reactor Internals Wear Report," March 1, 1974
2. Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors"

TOPIC: III-8.B Control Rod Drive Mechanism Integrity

(1) Definition:

Review and evaluate the reliability, operability and any reported mechanical failures in control rod drives.

(2) Safety Objective:

To assure that the integrity and operability of control rod drives is adequately maintained so that they will be capable of normal reactor control and prompt reactor shutdown, if required.

(3) Status:

The Division of Operating Reactors Engineering Branch is currently evaluating the failure modes and internal component redesigns of BWR control rod drives to preclude stress corrosion and thermal fatigue cracking. There have been no reported generic failures of PWR drives.

(4) Reference:

General Electric, NEDO-21021, "Test Program for Collet Retainer Tube," June 23, 1976.

TOPIC: III-8.C Irradiation Damage, Use of Sensitized Stainless Steel, and Fatigue Resistance

(1) Definition:

Review the safety aspects that affect reactor vessel internals integrity for compliance with 10 CFR Part 50, including radiation damage, use of sensitized stainless steel, and fatigue resistance.

(2) Safety Objective:

To assure continued reactor vessel internals integrity and compliance with 10 CFR Part 50 and applicable industry Codes and Standards.

(3) Status:

The Engineering Branch, Division of Operating Reactors, currently has no review programs relating to reactor vessel internals integrity.

(4) References:

1. 10 CFR Part 50, Appendix A
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
3. American Society of Testing Materials, ASTM A-262-70, "Standard Recommended Practices for Detecting Susceptibility to Intergranular Attack in Stainless Steels"
4. Regulatory Guides
   1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants"
   1.44, "Control of the Use of Sensitized Stainless Steel"
   1.61, "Damping Values for Seismic Design of Nuclear Power Plants"

TOPIC: III-8.D Core Supports and Fuel Integrity

(1) Definition:

Abnormal loading conditions on the core supports and fuel assemblies due to seismic events or loss-of-coolant accidents (LOCAs) could cause fuel damage due to impact between fuel assemblies and upper- and lower-grid plates or lateral impact between fuel assemblies and the core baffle wall. The resulting damage could result in loss of coolable heat transfer geometry, make it impossible to insert control rods, or cause releases of radioactive materials due to fuel pin failure.

(2) Safety Objective:

To assure that all credible loading conditions on core supports and fuel assemblies will not result in unacceptable fuel damage or distortion.

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(3) Status:

The Division of Operating Reactors is currently reviewing the dynamic loads imposed on the fuel assemblies during a LOCA. Independent analyses are being conducted by staff consultants.

(4) Reference:

American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant System" (NUREG-0649)

USI A-2 requires that an analysis be performed by licensees to assess the design adequacy of the reactor vessel supports and other structures to withstand the loads when asymmetric LOCA forces are taken into account. The staff has completed its investigation and concluded that an acceptable basis has been provided in NUREG-0609, "Asymmetric Blowdown Loads on PWR Primary Systems," January 1981, for performing and reviewing plant analyses for asymmetric LOCA loads. The structural acceptance criteria specified in NUREG-0609 are as follows:

The structural integrity of the primary system including the reactor pressure vessel, reactor pressure vessel internals, primary coolant loop, and components must be evaluated against appropriate acceptance criteria to determine if acceptable margins of safety exist. Allowable limits and appropriate loading combinations are set forth in Standard Review Plans (SRPs), which are listed in the table that follows. The staff recognizes that in some specific cases where "as-built" designs are being reevaluated for asymmetric LOCA loads, these design limits may be exceeded. Acceptance of alternative allowable limits will be based on a case-by-case evaluation of the safety margins.

Load-combination criteria in general were not addressed as part of this study. Currently the staff requires that seismic and LOCA response be combined, along with responses due to other loading as specified by the SRP. An acceptable method for combining elastically generated seismic and LOCA responses is provided in NUREG-0484. Acceptable methods for combining response generated by an inelastic LOCA analysis and elastic seismic analyses will be evaluated on a case-by-case basis.

Since USI A-2 also requires the investigation of seismic and LOCA response be combined, the evaluation required by USI A-2 is identical to SEP Topic III-8.D; therefore, this SEP topic has been deleted.

Item	SRP Section
Reactor pressure vessel	3.9.3
Reactor internals	3.9.5, 3.9.1
Primary coolant loop piping	3.9.3
ECCS piping	3.9.3
RPV, SG, pump supports	3.8.3
Biological shield wall	3.8.3
Steam-generator compartment wall	3.8.3
Neutron-shield tank	3.8.3

TOPIC: III-9 Support Integrity

(1) Definition:

Review the design, design loads, and materials integrity including corrosion and fracture toughness and the inservice inspection programs of supports and restraints including bolting for the reactor vessel, steam generator, reactor coolant pump, torus, and other Class 1, 2, and 3 safety-related components and piping systems.

(2) Safety Objective:

To assure adequate support and/or restraint of safety-related systems and components under normal and accident loads so that they will not be prevented from performing their intended functions because of support failures.

(3) Status:

The Division of Operating Reactors has ongoing programs to review component supports. Current emphasis is on primary system supports and on piping system supports and restraints (snubbers).

(4) References:

1. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
2. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Topics 3-5 and 3-43

(5) Basis for Deletion (Related TMI Task, USI, or other SEP Topic):

(a) USI A-12, "Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports" (NUREG-0510 and NUREG-0606)

The original scope of USI A-12 was the review of the steam generator and reactor coolant pump supports of pressurized water reactors.

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However, the staff has expanded the review to include other support structures, such as boiling water reactor (BWR) vessel supports, BWR pump supports, pressurized water reactor (PWR) vessel supports and PWR pressurizer supports (NUREG-0577, Section 1.3). This expanded review will be undertaken in accordance with the guidance of Section 4 of NUREG-0577.

(b) USI A-7, "MARK I Containment Long-Term Program" (NUREG-0649)

Support integrity of the torus is being evaluated under USI A-7. Under this task, a short-term program that evaluated Mark I containment has provided assurance that the Mark I containment system of each operating BWR facility would maintain its integrity and functional capability during a postulated loss-of-coolant accident. A longer term program for BWR facilities, not yet licensed, is planned wherein the NRC staff will evaluate the loads, load combinations, and associated structural acceptance criteria proposed by the Mark I Owners Group prior to the performance of plant-unique structural evaluations. The Mark I Owners Group has initiated a comprehensive testing and evaluation program to define design-basis loads for the Mark I containment system and to establish structural acceptance criteria which will assure margins of safety for the containment system which are equivalent to that which is currently specified in the ASME Boiler and Pressure Vessel Code. Also included in their program is an evaluation of the need for structural modifications and/or load mitigation devices to assure adequate Mark I containment system structural safety margins.

(c) USI A-24, "Qualification of Class 1E Safety-Related Equipment" (NUREG-0371 and NUREG-0606)

Snubber operability and degradation of seals are covered under USI A-24.

(d) USI A-46, "Seismic Qualification of Equipment in Operating Plants" (NUREG-0705)

Mechanical snubbers are covered under USI A-46.

(e) SEP Topic III-6, "Seismic Design Considerations"

Snubbers are evaluated for capacity under SEP Topic III-6.

(f) SEP Topic V-1, "Compliance With Codes and Standards (10 CFR 50.55a)"

Inservice inspection requirements for supports are covered under SEP Topic V-1, which refers to 10 CFR 50.55a. SEP plants currently have surveillance Technical Specifications on snubbers.

The evaluation required by USI A-12, A-7, A-24, and A-46 and SEP Topics III-6 and V-1 is identical to the evaluation required by SEP Topic III-9; therefore, this SEP topic has been deleted.

TOPIC: III-10.A Thermal-Overload Protection for Motors of Motor-Operated Valves

(1) Definition:

The primary objective of thermal overload relays is to protect motor windings of motor-operated valves (MOVs) against excessive heating. This feature of thermal overload relays could, however, interfere with the successful functioning of a safety-related system. In nuclear plant safety system application, the ultimate criterion should be to drive the valve to its proper position to mitigate the consequences of an accident, rather than to be concerned with degradation or failure of the motor due to excess heating.

(2) Safety Objective:

To assure that (1) thermal overload protection, if provided for MOVs, should have the trip setpoint at a value high enough to prevent spurious trips due to design inaccuracies, trip setpoint drift, or variation in the ambient temperature at the installed location; (2) the circuits which bypass the thermal overload protection under accident conditions should be designed to IEEE Std. 279-1971 criteria, as appropriate for the rest of the safety-related system; and (3) in MOV designs that use a torque switch instead of a limit switch to limit the opening or closing of the valve, the automatic opening or closing signal should be used in conjunction with a corresponding limit switch and thermal overload should remain as backup protection.

(3) Status:

The staff position (Reference 1) is implemented on designs of new applications (construction permit and operating license).

(4) References:

1. Standard Review Plan, Branch Technical Position EICSB 27, "Design Criteria for Thermal Overload Protection for Motors of Motor-Operated Valves"
2. Institute of Electrical and Electronics Engineers, IEEE Std. 279-1971, Criteria for Protection System for Nuclear Power Generating Stations"
3. Regulatory Guide 1.106, "Thermal Overload Protection for Electric Motors on Motor-Operated Valves"

TOPIC: III-10.B Pump Flywheel Integrity

(1) Definition:

Review the PWR reactor coolant pump flywheel inservice inspection programs of operating plants to assure that they comply with the intent of Regulatory Guide 1.14 and review reports of flywheel flaws if found by inservice inspections. (BWR reactor coolant pumps do not have flywheels.)

(2) Safety Objective:

To assure that pump flywheel integrity is maintained to prevent failure at normal operating speeds and at speeds that might be reached under accident conditions and thus preclude the generation of missiles.

(3) Status:

The inservice inspection programs for flywheels of older PWRs have not been reviewed for compliance with the intent of Regulatory Guide 1.14.

(4) Reference:

Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity"

TOPIC: III-10.C Surveillance Requirements on BWR Recirculation Pumps and Discharge Valves

(1) Definition:

At facilities which have completed the low pressure coolant injection system (LPCIS) modification, the recirculation pump discharge valves and bypass valves are now required to close upon initiation of LPCIS. The closure of these discharge valves is necessary to isolate a pipe break in a suction line to prevent loss of cooling water by reverse flow through the recirculation pump or its bypass line and out the break.

(2) Safety Objective:

To assure effective core cooling in the event of a BWR recirculation line break on the pump suction line by closing the pump discharge valve and bypass line valve.

(3) Status:

All licensees of facilities with completed LPCIS modification have been sent letters requesting that they apply for a license amendment to incorporate technical specification surveillance requirements on recirculation pump discharge valves and bypass valves. New BWRs have the LPCIS modification and technical specification surveillance requirements.

(4) Reference:

NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) Issue 3-46, June 17, 1977

TOPIC: III-11 Component Integrity

(1) Definition:

Review licensee's criteria, testing procedures, and dynamic analyses employed to assure the structural integrity and functional operability of safety-related mechanical equipment under faulted conditions and accident

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loads. Included are mechanical equipment such as pumps, valves, fans, pump drives, heat exchanger tube bundles, valve actuators, battery and instrument racks, control consoles, cabinets, panels, and cable trays.

(2) Safety Objective:

To confirm the ability of safety-related mechanical equipment having experienced problems to function as needed during and after a faulted or accident condition. The capability of safety-related mechanical equipment to perform necessary protective actions is essential for plant safety.

(3) Status:

This review is not currently under way in the Divisions of Operating Reactors.

(4) References:

1. 10 CFR Part 50, Section 50.55a
2. 10 CFR Part 50, Appendix A, GDC 2, 4, 14, and 15
3. Standard Review Plan, Section 3.9.2
4. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III,
5. Regulatory Guides
   1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing"
   1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants"
6. Institute of Electrical and Electronics Engineers, IEEE Std. 344-1975, "Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations"
7. Standard Review Plan, Section 3.9.3

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-46, "Seismic Qualification of Equipment in Operating Plants" (NUREG-0606 and NUREG-0705)

The component integrity (both structural integrity and functional operability) for safety-related mechanical and electrical equipment for all operating plants including SEP plants will be addressed in this new USI (A-46).

(b) USI A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant System" (NUREG-0649)

The assessment of faulted loads for the primary loop is being performed under USI A-2. Furthermore, the assessment of high-energy pipe breaks considers the effect of accident loads with regard to jet impingement, pipe whip, and other reaction loads.

(c) SEP Topic III-6, "Seismic Design Considerations"

The evaluation of equipment structural integrity under seismic loads will be performed under SEP Topic III-6.

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The evaluations required by USI A-46 and A-2 and SEP Topic III-6 are identical to SEP Topic III-11; therefore, this SEP topic has been deleted.

TOPIC: III-12 Environmental Qualification of Safety-Related Equipment

(1) Definition:

Safety-related electrical and mechanical equipment that is required to survive and function under environmental conditions calculated to result from a loss-of-coolant accident (LOCA) or a postulated main steam line break accident inside containment must be environmentally qualified. In addition, determine whether environment-induced failures of nonsafety-related equipment could interfere with the operation of safety equipment. Special attention should be given to the effect of beta radiation on exposed organic surfaces, such as gaskets.

(2) Safety Objective:

To assure that the mechanical and Class IE electrical equipment of safety systems has been qualified for the most severe environment (temperature, pressure, humidity, chemistry, and radiation) of design basis accidents.

(3) Status:

Westinghouse is conducting a verification program which is expected to be completed by the end of 1977 for those plants qualified to IEEE 323-1971. The Office of Nuclear Regulatory Research is sponsoring programs relating to Class IE equipment qualification, the results of which can be utilized to determine the adequacy of the equipment previously qualified.

(4) References:

1. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue 25, "Qualification of Safety-Related Equipment," December 1976
2. Division of Operating Reactors, DOR Technical Activities, Category B, Item 34, "Environmental Qualifications of Safety-Related Equipment (Post LOCA)," May 1977
3. Division of Systems Safety, DSS Technical Activities, Category A, Item 33, "Qualification of Class IE Safety-Related Equipment," April 1977
4. Regulatory Guide 1.89, "Qualification of Class IE Equipment for Nuclear Power Plants"

(5) Basis for Deletion (Related TMI Task, USI, or other SEP Topic):

- USI A-24, "Qualification of Class IE Safety-Related Equipment" (NUREG-0371 and NUREG-0606)

The issue identified in Reference 1 (NUREG-0153, Item 25) and the review criteria, that is, Regulatory Guide 1.89, are identical to those specified in USI A-24. The Task Action Plan for USI A-24

(NUREG-0371) covers the environmental qualification of both electrical and mechanical safety-related equipment.

The evaluation required by USI A-24 is identical to SEP Topic III-12; therefore, this SEP topic has been deleted.

TOPIC: IV-1.A Operation With Less Than All Loops in Service

(1) Definition:

A number of BWR and PWR licensees have requested authorization to operate with one of the recirculation loops (BWR) or steam generator loops (PWR) out of service. These proposals are being reviewed generically with regard to analytical methods. Plant-specific reviews will be done to determine appropriate Technical Specification limits. Plant-specific reviews will address results of LOCA analyses using generically approved methods. Analysis of accidents (other than LOCA) and operating transients resulting from operation in the (N-1) loop mode have been reviewed on a "lead plant basis." Most of this effort has been completed. Tests have been conducted by General Electric which show that significant core flow asymmetries do not exist with single-loop operation for two-loop plants; however, there is backflow through inactive jet pumps. Therefore, for single-loop operation, modifications are necessary in trip settings which take inputs from jet pump drive flow. These will be determined on a plant-specific basis.

(2) Safety Objective:

To provide assurance that operation with less than all coolant loops in operation will not result in decreased safety margins.

(3) Status:

A combination of generic and plant-specific reviews is being performed on both BWRs and PWRs.

TOPIC: IV-2 Reactivity Control Systems Including Functional Design and Protection Against Single Failures

(1) Definition:

General Design Criterion 25 requires that the reactor protection system be designed to assure that fuel-damage limits are never exceeded in the event of any single failure of the reactivity control systems. Reactivity control systems need not be designed single failure proof, but the protection system (which is designed against single failures) should be capable of limiting fuel damage in the event of a reactivity control system single failure.

(2) Safety Objective:

To assure that for all credible reactivity control system failures, the protection system will limit fuel damage to acceptable limits.

(3) Status:

NRC has concluded that revisions to existing licenses are not warranted. Staff effort on this issue will continue at a low level.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 6, "Protection Against Single Failures in Reactivity Control Systems," December 1976.
2. Standard Review Plan, Section 15.4.3

TOPIC: IV-3 BWR Jet Pump Operating Indications

(1) Definition:

If a jet pump BWR operates with a failed jet pump, it may be impossible to reflood the core in the event of a LOCA. Some BWRs have experienced jet pump instrument sensing line failures. With a sensing line failed, it may not be possible to accurately measure core flow or to detect failure of a jet pump.

(2) Safety Objective:

To assure that the core flow can be determined. Also to assure the ability to detect a jet pump failure for a range of crack/break sizes at various locations on the pump.

(3) Status:

This issue is currently being reviewed for Dresden Units 2 and 3 and Quad Cities Units 1 and 2. The topic has generic implications for all jet pump BWR plants.

(4) References:

1. Letters from Commonwealth Edison Company to NRC, dated September 19, 1975, March 3, 1976, and June 7, 1976.
2. Letter from NRC to Commonwealth Edison Company, dated January 19, 1976.
3. Memorandum from J. H. Sniezek, NRC, to D. L. Ziemann, dated November 19, 1975.

TOPIC: V-1 Compliance With Codes and Standard (10 CFR 50.55a)

(1) Definition:

Review the licensee's inservice inspection and testing programs for Class 1, 2, and 3 pressure vessels, piping, pumps and valves and other safety-related components to assure compliance with the American Society of Mechanical Engineers (ASME) Code, Sections III and XI, as required by 10 CFR 50.55a. This review will also include review of the inservice inspection and testing program applicable to isolation condensers of the early operating BWRs.

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(2) Safety Objective:

To assure that the initial integrity of components is maintained throughout service life.

(3) Status:

NUREG-0081 was completed for reactor vessels not designed to ASME Code, Section III. The Engineering Branch conducts a generic review of all plants for compliance with inspection requirements of 10 CFR 50.55a(g) and fracture toughness requirements of 10 CFR 50.55a(i). This program will continue for the life of operating reactors.

(4) References:

1. 10 CFR Part 50, Section 50.55a
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Sections III and XI
3. NUREG-0081, "Evaluation of the Integrity of Reactor Vessels Designed to ASME Code, Section I and/or VIII," July 1976
4. Memorandum from V. Stello, NRC, to B. H. Grier, October 12, 1976

TOPIC: V-2 Applicability of Code Cases

(1) Definition:

Review Code Cases currently accepted by the NRC, as indicated in Regulatory Guides 1.84 and 1.85.

(2) Safety Objective:

To assure that only those Code Cases which are acceptable to the NRC are utilized by the licensee in the design, fabrication, or repair of the plant. The use of Code Cases other than those contained in Regulatory Guides 1.84 and 1.85 are addressed on a case-by-case basis to assess their acceptability.

(3) Status:

The Engineering Branch, Division of Operating Reactors, routinely reviews design modifications and component repairs (for example, reactor vessel nozzles) to assure compliance with NRC acceptable Code Cases. The program is ongoing on an as-needed basis.

(4) References:

Regulatory Guides
1.84, "Design and Fabrication Code Case Acceptability - ASME Section III, Division 1"
1.85, "Materials Code Case Acceptability - ASME Section III, Division 1"

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TOPIC: V-3 Overpressurization Protection

(1) Definition:

Inadvertent overpressurization of the primary system at temperatures below the nil ductility transition temperature may result in reactor vessel failure during heatup and pressurization. Such overpressure transients are caused by pressure surges when the primary system is water solid. The most severe transients have occurred when a charging pump starts up or inadvertent closing of a letdown valve with a charging pump running. Pressure temperature limits as a function of neutron fluence of the material at the reactor vessel beltline are specified in 10 CFR 50, Appendix G. All PWR licensees have been directed to institute interim administrative procedures to prevent damaging pressure transients and on a longer time scale to provide permanent protection which will probably include hardware changes such as high-capacity safety relief valves.

(2) Safety Objective:

To protect the primary system from potentially damaging overpressurization transients during plant pressurization and heatup.

(3) Status:

Generic review of all PWR licensee submittals is under way. Criteria for evaluation have been developed and refined by the Office of Nuclear Reactor Regulation and the Office of Nuclear Regulatory Research. An effort is being made to complete the review sufficiently early to ensure installation of mitigating systems by the end of 1977.

(4) Reference:

NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR to NRR Staff," November 1976

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-26, "Reactor Vessel Pressure Transient Protection" (NUREG-0410)

  Under USI A-26, licensees were requested to modify their systems and procedures to protect against low temperature overpressurization. All operating PWRs have made these modifications, and safety evaluation reports for the SEP plants have been issued.

  The evaluation required by USI A-26 is identical to SEP Topic V-3; therefore, this SEP topic has been deleted.

TOPIC: V-4 Piping and Safe-End Integrity

(1) Definition:

Review the safety aspects that affect BWR and PWR piping and safe-end integrity for compliance with 10 CFR Part 50, including fracture toughness, flaw evaluation, stress corrosion cracking in BWR and PWR piping, and control of materials and welding.

(2) Safety Objective:

To ensure continued piping integrity and compliance with 10 CFR Part 50 and applicable industry codes and standards.

(3) Status:

The Engineering Branch, Division of Operating Reactors, is conducting an ongoing program that includes the as-needed review of those aspects necessary to ensure the continuing integrity of piping systems important to safety including stress corrosion cracking of BWR coolant pressure boundary piping. This program will continue for the life of operating reactors.

(4) Reference:

American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section XI

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-42, "Pipe Cracks in Boiling Water Reactors" (NUREG-0510)

The scope of USI A-42 is the study of stress corrosion cracking in BWR piping. NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," is the resolution of USI A-42 and presents staff positions.

(b) USI A-10, "BWR Feedwater Nozzle Cracking and Control Rod Drive Hydraulics Return Line Nozzle Cracking" (NUREG-0649)

(c) NRR Generic Activity C-7, "PWR System Piping" (NUREG-0471)

The scope of this activity is the study of stress corrosion cracking in PWR piping. NUREG-0691, "Investigation and Evaluation of Cracking Incidents in Piping in Pressurized Water Reactors," recommends the same corrective actions (pp. 2-12) proposed for BWRs in NUREG-0313, Revision 1, USI A-42.

The evaluation required by USI A-42 and Task C-7 is identical to the evaluation required by SEP Topic V-4; therefore, this SEP topic has been deleted.

TOPIC: V-5 Reactor Coolant Pressure Boundary (RCPB) Leakage Detection

(1) Definition:

Reactor primary coolant leakage detection systems are a significant means of preventing primary system boundary failure by identifying leaks before failures occur.

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(2) Safety Objective:

To provide reliable and sensitive leakage detection systems to identify primary system leaks at an early stage before failures occur.

(3) Status:

This issue has been resolved for all plants which have recently received an operating license by requiring conformance to Regulatory Guide 1.45. Individual older plants have not been systematically reviewed and leakage detection systems may need upgrading on a plant-by-plant basis.

(4) References:

1. Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems"
2. Standard Review Plan, Section 5.2.5

TOPIC: V-6 Reactor Vessel Integrity

(1) Definition:

Review the safety aspects that affect BWR and PWR reactor vessel and nozzle integrity for compliance with 10 CFR Part 50, including fracture toughness, neutron irradiation, evaluation of surveillance programs, operating limitations, inservice inspection and flaw evaluation, and transient analyses.

(2) Safety Ojective:

To assure continued reactor vessel integrity and compliance with 10 CFR Part 50 and applicable industry codes and standards.

(3) Status:

The Engineering Branch, Division of Operating Reactors, is conducting ongoing programs that include the periodic review of aspects necessary to ensure the continued integrity of reactor vessels. These programs include BWR feedwater and control rod drive nozzle cracking, low upper-shelf toughness, radiation effects, reactor vessel materials surveillance, and updating of operating plants' inservice inspection programs and will continue for the life of operating reactors.

(4) References:

1. NUREG-0312, "Interim Technical Report on BWR Feedwater and Control Rod Drive Return Line Nozzle Cracking," July 1977
2. 10 CFR Part 50, Appendix G
3. Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials"
4. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III, Appendix G
5. American Society of Testing Materials, ASTM E185, "Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels"

6. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section XI
7. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Issue 3-9, 3-21, 3-41

TOPIC: V-7 Reactor Coolant Pump Overspeed

(1) Definition:

Review the potential for reactor coolant pumps to fail because of overspeed in the unlikely event of a major loss-of-coolant accident (LOCA).

(2) Safety Objective:

To assure that, in the event of a major LOCA, a reactor coolant pump assembly is not driven to a speed which would cause structural failure of the unit and result in missiles which could increase the consequences of the LOCA. Of greatest concern are the PWR pump flywheels because of their mass and rotational energy.

(3) Status:

An indepth review of this topic was performed by the Atomic Energy Commission staff and reported to the Advisory Committee on Reactor Safeguards (ACRS) in 1973 (Reference 1). The staff concluded that, because of the small likelihood for the occurrence of a pump overspeed event that could seriously increase the consequences resulting from a LOCA (less than 10^{-8} per plant year), the action taken by the staff to assess this problem in a generic fashion outside the context of individual application reviews is an acceptable course to follow. A generic experimental program to be completed in 1978 by the Electric Power Research Institute is expected to provide data to verify pump model overspeed predictions.

(4) References:

1. Letter from R. C. DeYoung, NRC, to Harold G. Mangelsdorf, ACRS, August 6, 1973, transmitting "Report on Reactor Coolant Pump Overspeed During a LOCA," August 3, 1973.
2. Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity"

TOPIC: V-8 Steam Generator (SG) Integrity

(1) Definition:

Review the safety aspects affecting operation of steam generators including secondary water chemistry, tube plugging criteria, inservice inspection, possibly including a dimensional inspection for proper evaluation of denting, steam generator tube leakage, tube denting, flow-induced vibration of steam generator tubes, tube repair, and tube bundle or steam generator replacement.

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(2) Safety Objective:

To ensure that acceptable levels of integrity of that portion of the reactor coolant pressure boundary made up by the steam generator are maintained in accordance with current codes, standards, and/or regulatory criteria during normal and postulated accident conditions. The integrity of the steam generator is needed to ensure that leakage following a postulated design basis accident will not result in doses to the public in excess of 10 CFR Part 100 guidelines and that the emergency core cooling systems will be able to perform their safety functions.

(3) Status:

Review of this topic is being performed by the Division of Operating Reactors (DOR). This effort will continue for the life of operating reactors.

(4) References:

1. Regulatory Guide 1.83, Rev. 1, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes"
2. Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes"
3. 10 CFR Part 50, Appendix A, GDC 30 and 32
4. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), 3-27

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-3, A-4, A-5, "Westinghouse, Combustion Engineering, and Babcock and Wilcox Steam Generator Tube Integrity" (NUREG-0649)

  The definition of this topic and the references cited are covered by USI A-3, A-4, and A-5. The evaluation for USI A-3, A-4, and A-5 is identical to SEP Topic V-8; therefore, this SEP topic has been deleted.

TOPIC: V-9 Reactor Core Isolation Cooling System (BWR)

(1) Definition:

Reactor core isolation cooling (RCIC) has not been classified as a safety system. On GESSAR, for certain small breaks, GE assumed credit for RCIC as a backup for HPCI. The staff required GE to reclassify the RCIC system on the GESSAR 238 standard NSSS as a safety system.

(2) Safety Objective:

To ensure that the RCIC system is qualified as a safety system where credit is assumed in the safety analysis.

(3) Status:

GE has agreed to reclassify RCIC as a safety system on the GESSAR docket.

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TOPIC: V-10.A Residual Heat Removal System Heat Exchanger Tube Failures

(1) Definition:

Residual heat removal (RHR) heat exchangers are designed to remove residual and decay heat so that the reactor can be placed in a safe cold shutdown condition and to maintain core cooling following a postulated loss-of-coolant accident. Some light-water reactors (LWRs) have a pressure control system on the cooling water piping system which maintains the pressure of the cooling water higher than the primary coolant pressure in the primary coolant side of the heat exchanger during plant cooldown operations. A leak in the tubes could result in back leakage of coolant water into the primary loop. Pressure in the cooling water side is maintained higher than that in the primary coolant side so that in the event of a tube failure there would be no leakage of radioactive fluids into the environment. Cooling water passing from the cooling water side of the heat exchanger into the primary coolant water could introduce impurities such as chlorides into the primary coolant system.

(2) Safety Objective:

To assure that impurities from the cooling water system are not introduced into the primary coolant in the event of an RHR heat exhanger tube failure.

(3) Status:

Recently there have been several RHR heat exchanger tube failures at operating BWRs. This issue has been defined as a DOR Category B Technical Activity.

TOPIC: V-10.B Residual Heat Removal System Reliability

(1) Definition:

In all current plant designs, the residual heat removal (RHR) system has a lower design pressure than the reactor coolant system (RCS). In most current designs, the system is located outside of containment and is part of the emergency core cooling system. However, it is possible for the RHR system to have different design characteristics. For example, the RHR system might have the same design pressure as the RCS, or be located inside of containment. The functional, isolation, pressure relief, pump protection, and test requirements for the RHR system are of concern in the safety review of reactor plants. Three types of RHR system designs are defined in Branch Position RSB 5-1.

On June 24, 1976, the Regulatory Requirements Review Committee approved a revision of Standard Review Plan, Section 5.4.7 requiring a capability to go from hot to cold shutdown without offsite power and that all components necessary for cooldown from hot shutdown must be designed to safety grade seismic I standards, and be operable from the control room. System must be designed to meet the single failure criterion.

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(2) Safety Objective:

To ensure reliable plant shutdown capability using safety-grade equipment.

(3) Status:

Because of vendor concern over the impact of the revision, a review was conducted of three PWR plants, and as a result of this review, the staff is proposing that Branch Position RSB 5-1 be modified but that the functional requirements be retained.

(4) References:

1. Standard Review Plan, Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal System"
2. Standard Review Plan, Section 5.4.7
3. Memorandum from E. G. Case, NRC, to L. V. Gossick, July 15, 1976.
4. Summary of meeting September 22, 1976, "Capability To Achieve Cold Shutdown Using Safety Grade Systems and Equipment," C. O. Thomas, Docket No. STN-50-545, October 5, 1976.

TOPIC: V-11.A Requirements for Isolation of High- and Low-Pressure Systems

(1) Definition:

Several systems that have a relatively low design pressure are connected to the reactor coolant pressure boundary. The valves that form the interface between the high- and low-pressure systems must have sufficient redundancy and interlocks to assure that the low-pressure systems are not subjected to coolant pressures that exceed design limits. The problem is complicated since under certain operating modes (for example, shutdown cooling and emergency core cooling system injection), these valves must open to assure adequate reactor safety.

(2) Safety Objective:

To assure that adequate measures are taken to protect low-pressure systems connected to the primary system from being subjected to excessive pressure which could cause failures and in some cases potentially cause a loss-of-coolant accident outside of containment.

(3) Status:

A preliminary review of a representative operating plant of each nuclear steam supply system vendor was undertaken. Each low-pressure system connected to the reactor coolant pressure boundary and penetrating the containment was examined. The investigation of a few potential areas of concern is continuing.

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TOPIC: V-11.B Residual Heat Removal System Interlock Requirements

(1) Definition:

The residual heat removal (RHR) system is normally located outside of primary containment. It is an intermediate pressure system (usually 600 psia) and has motor-operated valve (MOV) isolation valves connecting it to the reactor coolant system (RCS). If the RHR system were inadvertently connected to the RCS while the RCS is at pressure, a loss-of-coolant accident (LOCA) could result with a loss of all capability of core reflooding since the coolant inventory could be lost outside of containment. To prevent inadvertent opening of the MOVs while the RCS is at pressure, an "OPEN PERMISSIVE" interlock is provided.

If the operator shuts only one of the isolation valves prior to pressurizing the RCS, there is a single valve RCS pressure boundary.

To ensure that both MOVs are shut during a startup and heatup, an "AUTO-CLOSURE" interlock is provided that closes the MOVs.

(2) Safety Objective:

To ensure that operating reactor plants are adequately protected from overpressurizing the RHR system and potentially causing a LOCA outside of containment.

(3) Status:

Several PWR plants do not have the auto closure feature on the RHR, and at least one does not have the open permissive feature. Plants should be reviewed on a case-by-case basis factoring in (1) ASME Code safety valve setting and capacity, (2) interlocks, (3) closure time of MOVs, and (4) location of RHR.

(4) References:

1. Proposed Branch Technical Position RSB-5-1, "Design Requirements of the Residual Heat Removal System"
2. Regulatory Requirements Review Committee Meeting No. 50, June 24, 1976
3. 10 CFR Part 50, Appendix A, GDC 34
4. Memorandum from J. Angelo to R. C. DeYoung, V. Stello, et al., NRC, Subject: "RP-TR Staff Meeting of February 13, 1974 Regarding the Requirements on Shutdown Cooling Systems," February 28, 1974
5. Letter from R. Boyd, NRC, to C. Eicheldinger, Westinghouse Electric Corporation, November 12, 1975
6. Letter from R. Boyd, NRC, to I. Stuart, General Electric Company, November 12, 1975
7. Letter from R. Minogue, NRC, to J. D. Geier, Illinois Power Company, July 8, 1975

TOPIC: V-12.A Water Purity of BWR Primary Coolant

(1) Definition:

Review the primary water monitoring and reactor water cleanup system capabilities, including the water purity, to determine if the maintenance of the necessary purity levels complies with Regulatory Guide 1.56. Review limits on quality control and defined provisions in the event of demineralizer breakthrough.

(2) Safety Objective:

To assure that the water purity level is acceptably low to minimize the potential for intergranular stress corrosion cracking of austenitic stainless steel piping in the reactor coolant pressure boundary of BWRs, including assuring the implementation of Regulatory Guide 1.56.

(3) Status:

Recommendations for specifying the use of additional conductivity measurements and monitoring at various locations, plus the use of pH and chloride measurements, have been submitted to the Division of Standards Development to initiate a revision of Regulatory Guide 1.56, "Maintenance of Water Purity in Boiling Water Reactors," dated June 1973. To date, a generic review of operating BWRs has not been initiated and the current regulatory guide has been implemented in the Technical Specifications of only a few operating plants.

(4) Reference:

Memorandum from R. E. Heineman, to R. B. Minogue, NRC, Subject: "Request for Revision of Regulatory Guide 1.56," 1973

TOPIC: V-13 Waterhammer

(1) Definition:

Waterhammer events have occurred in light water reactor systems. Waterhammer events increase the probability of pipe breaks and could increase the consequences of certain events such as the loss-of-coolant accident. The types of waterhammer, the vulnerable systems (for example, containment spray, service water, feedwater, and steam), and the safety significance of waterhammer have been identified and defined in a staff report of May 1977.

(2) Safety Objective:

To reduce the probability of waterhammer events that have the potential to lead to pipe ruptures in light-water reactor systems which are needed to mitigate the consequences of accidents or that might increase the consequences of accidents previously analyzed.

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(3) Status:

Generic review is under way. On March 10, 1977, an interdivisional Division of Operating Reactors/Division of Systems Safety technical review group was formed to investigate the waterhammer issue and to develop a program for its appropriate consideration in licensing reviews and for operating reactors. Consultant work has been performed by CREARE and Livermore Labs.

(4) References:

1. "Water Hammer in Nuclear Power Plants," NRC Staff Report, June 1, 1977
2. Wallis, G. B., P. H. Rothe, et al., "An Evaluation of PWR Steam Generator Water Hammer" (draft), CREARE Inc., February 1977
3. Sutton, S. B., "An Investigation of Pressure Transient Propagation in Pressurized Water Reactor Feedwater Lines" (preliminary), Lawrence Livermore Laboratory, April 15, 1977
4. Office of Nuclear Reactor Regulation, NRR Technical Activities, Category A, Item 1, "Water Hammer," May 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-1, "Water Hammer" (NUREG-0649)

The references cited in this topic were the precursors of USI A-1. The evaluation required for USI A-1 is identical to SEP Topic V-13; therefore, this SEP topic has been deleted.

TOPIC: VI-1 Organic Materials and Postaccident Chemistry

(1) Definition:

(a) Organic materials
The design basis for selection of paints and other organic materials is not documented for most operating reactors. Therefore, there is a need to review the suitability of paints and other organic materials used inside containment, including the possible interactions of the decomposition products of organic materials with engineered safety features (such as filters).

(b) Postaccident chemistry
Low pH solutions that may be recirculated within containment after a design basis accident (DBA) may accelerate chloride stress corrosion cracking which may lead to equipment failure or loss of containment integrity. Low pH may also increase the volatility of dissolved iodines with a resulting increase in radiological consequences.

(2) Safety Objective:

(a) Organic materials
To assure that organic paints and coatings used inside containment do not behave adversely during accidents when they may be exposed to high radiation fields. In particular, the possibility of coatings clogging sump screens should be minimized.

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(b) Postaccident chemistry
To assure that appropriate methods are available to raise or maintain the pH of solutions expected to be recirculated within containment after a DBA.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. Standard Review Plan, Sections 6.1.2 and 6.1.3
2. Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants"

TOPIC: VI-2.A Pressure-Suppression-Type BWR Containments

(1) Definition:

BWR pressure-suppression-type containments (for example, Mark I containment) are subjected to hydrodynamic loads during the blowdown phase of a loss-of-coolant accident (LOCA). These loads have the potential for damaging the components and structures (wetwell, internal structures, restraints, supports and connected systems) of the containment. During a relief valve blowdown into the suppression pool, the wetwell (torus) shell and safety/relief valve restraints may be overstressed. The hydrodynamic loads were not explicitly identified and included in the design of the Mark I pressure-suppression containment.

(2) Safety Objective:

To assure that the structural integrity of pressure-suppression pool containments is maintained under hydrodynamic loading conditions. It has been determined that the upward forces during the blowdown phase following a LOCA potentially cause the Mark I torus to be lifted, causing failure of connecting systems and supports and leading to loss of the containment integrity. Structural modifications and/or changes in the mode of operation might be necessary to assure adequate safety margins.

(3) Status:

Mark I containments are currently evaluated in a two-step generic review program: The Short-Term Program (STP), completed May 1977, has focused on the determination of the magnitude and significance of hydrodynamic loads. In the Long-Term Program (LTP), to be completed by late 1978, the design basis loads will be finalized and the capability of the containment to withstand the loads within the original design structural margins will be verified. This verification will be based in part on research results from NRC and industry sponsored programs. As a result of the STP, the staff required that Mark I plants be operated with a drywell to wetwell differential pressure of at least 1 psi to reduce the vertical loads. In addition, some licensees have modified the torus support system for additional safety margin.

(4) References:

1. NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) - Generic Issues (April 1977)
   - a. Mark I Containment - STP Technical Specifications
   - b. Mark I Containment Evaluation - STP
   - c. Mark I Containment Evaluation - LTP
   - d. Mark I Safety/Relief Valve Line Restraints in Torus
2. Division of Operating Reactors, DOR Technical Activities, Category A, April 1977
   - a. Item 2, "Mark I Containment STP"
   - b. Item 3, "Mark I Containment LTP"
   - c. Item 23, "Mark II Containment"
3. Division of Operating Reactors, DOR Technical Activities, Category B, Item 12, "Assessment of Column Buckling Criteria," May 1977
4. Division of Systems Safety, DSS Technical Activities, Category A, Item 31, "Determination of LOCA and SRV Pool Dynamic Loads for Water Suppression Containments," April 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-7, "Mark I Containment Long-Term Program" (NUREG-0649)

Under this task, a short-term program that evaluated Mark I containment has provided assurance that the Mark I containment system of each operating BWR facility would maintain its integrity and functional capability during a postulated LOCA. A longer term program for BWR facilities, not yet licensed, is planned wherein the NRC staff will evaluate the loads, load combinations, and associated structural acceptance criteria proposed by the Mark I Owners Group prior to the performance of plant-unique structural evaluations. The Mark I Owners Group has initiated a comprehensive testing and evaluation program to define design basis loads for the Mark I containment system and to establish structural acceptance criteria which will assure margins of safety for the containment system which are equivalent to that which is currently specified in the ASME Boiler and Pressure Vessel Code. Also included in their program is an evaluation of the need for structural modifications and/or load-mitigation devices to assure adequate Mark I containment system structural safety margins.

The long-term program for USI A-7 will assure that all plants with Mark I containments are able to tolerate, without loss of function, the LOCA-induced hydrodynamic loads.

The evaluation required by USI A-7 is identical to SEP Topic VI-2.A; therefore, this SEP topic has been deleted.

TOPIC: VI-2.B Subcompartment Analysis

(1) Definition:

The rupture of a high energy line inside a containment subcompartment can cause a pressure differential across the walls of the subcompartment. In

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the case of a rupture of a PWR main coolant pipe adjacent to the reactor vessel, the subcooled blowdown produces pressure differentials in the annulus between the reactor vessel and the shield wall and also within the reactor vessel across the core barrel. This asymmetric pressure distribution generates loads on the reactor vessel support and on reactor vessel internals, on other equipment supports, and on subcompartment structures which have not been analyzed previously for most operating reactors.

(2) Safety Objective:

To assure that the reactor vessel supports, reactor vessel internals, and other equipment supports and subcompartment structures are designed with an adequate margin against failure due to these loads. The failure could result in a loss of emergency core cooling system capability.

(3) Status:

The staff is reviewing the nuclear steam supply system vendor and architect-engineer design codes used to calculate the loads produced by the asymmetric pressure distribution. Analyses have been completed for a limited number of operating plants. The W TMD code is approved. Bechtel, Gilbert, and United Engineering have submitted codes for review.

(4) References:

1. NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) - Generic Issue, Item 3-5, "Asymmetric LOCA Loads - PWR," April 1977
2. Division of Operating Reactors, DOR Technical Activities, Category A, Item 32, "Asymmetric LOCA Loads (Reactor Vessel Support Problem)," April 1977
3. Division of Systems Safety, DSS Technical Activities, Category A, Item 14, "Asymmetric Blowdown Loads on Reactor Vessel," April 1977
4. Division of Project Management, DPM Technical Activities, Category A, Item 2, "Reactor Vessel Supports (Asymmetric LOCA Loads From Sudden Subcooled Blowdown)," April 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant System" (NUREG-0649)

  The references cited in this topic were the precursors of USI A-2. The evaluation required for USI A-2 is identical to SEP Topic VI-2.B (see also SEP Topic III-8.D); therefore, this SEP topic has been deleted.

TOPIC: VI-2.C Ice Condenser Containment

(1) Definition:

Operating experience from the D. C. Cook plant has indicated that sublimation and melting of ice causes a loss of ice inventory and related functional performance problems for the ice consenser system.

(2) Safety Objective:

To assure that a sufficient ice inventory is maintained and to assure the functional performance of the ice condenser system.

(3) Status:

The results of the surveillance program for ice inventory and of the functional performance testing (for example, operation of vent doors) are periodically reviewed by the staff to determine whether the surveillance frequencies should be increased or other action should be taken. Recent surveillance testing indicates that the ice inventory is acceptable and that the D. C. Cook plant can be operated safely for the current fuel cycle. CONTEMPT-4 long-term ice condenser code is expected to be completed by Edgerton, Germeshausen & Grier in October 1977.

(4) Reference:

Division of Operating Reactors, DOR Technical Activities, Category B, Item 53, "Ice Condenser Containments," May 1977

TOPIC: VI-2.D Mass and Energy Release for Postulated Pipe Breaks Inside Containment

(1) Definition:

Review the methods and assumptions of the mass and energy release model, including containment temperatures and pressure response, that were used in previously performed analyses of high-energy line breaks inside containment, including the main steam line break.

(2) Safety Objective:

To assure that design basis conditions (for example, design pressure and temperature) for the containment structure and safety-related equipment are adequate. Determine if the models used in the earlier analyses provide adequate margins of safety when compared with the assumptions and models for current analytical techniques.

(3) Status:

Mass and energy release models, including containment response models, are being reassessed to determine the degree of conservatism in the prediction of the containment pressure and temperature transient resulting from a PWR main steam line break. Application of those models to operating plants is contingent on the results of this reassessment. Mass and energy release models for operating BWR plants are considered in the Mark I Long-Term Program and other BWR review efforts.

(4) References:

1. Division of Operating Reactors, DOR Technical Activities, Category B, May 1977

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    a. Item 1, "Pipe Break Inside Containment"
    b. Item 2, "Mass and Energy Release to Containment"
2. Division of Systems Safety, DSS Technical Activities, Category A, April 1977
    a. Item 7, "Pipe Rupture Design Criteria"
    b. Item 29, "Main Steam Line Break Inside Containment"
3. Division of Systems Safety, DSS Technical Activities Report, Item I-C.B.1, "Mass and Energy Release to Containment," December 1975

TOPIC: VI-3 Containment Pressure and Heat Removal Capability

(1) Definition:

The temperature and pressure conditions inside containment due to a postulated loss-of-coolant accident (LOCA), main steam line or feedwater line break depend on the effectiveness of passive heat sinks and active heat removal systems (for example, containment spray system).

(2) Safety Objective:

To assure that the maximum temperature and pressure following a LOCA, main steam, or feedwater line break have been calculated with conservative assumptions and to assure that the passive heat sinks and active heat removal systems provide the full heat removal capability required to maintain the pressure and temperature below the design pressure and temperature of the containment, of safety-related equipment, and instrumentation inside containment.

(3) Status:

The modified CONTEMPT computer code properly accounts for the condensation of superheated steam on containment passive heat sinks. The effects on the design temperatures within the containment are being studied for plants under licensing review.

(4) References:

1. Standard Review Plan, Section 6.2.1.1.A
2. Division of Systems Safety, DSS Technical Safety Activities Report, December 1975
3. Division of Operating Reactors, DOR Technical Activities, Category B, Item 62, "Effective Operation of Containment Sprays in LOCA," May 1977

TOPIC: VI-4 Containment Isolation System

(1) Definition:

Isolation provisions of fluid system of nuclear power plants limit the release of fission products from the containment for postulated pipe breaks inside containment and thus prevent the uncontrolled release of primary system coolant as a result of postulated pipe breaks outside containment. This must be accomplished without endangering the performance of postaccident safety systems. Review the primary containment

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isolation provisions, in particular, the containment sump lines and fluid systems penetrating containment. Review the design bases for containment ventilation system isolation valves to determine potential releases from the containment. Review the containment purge mode during normal operation with respect to various accident scenarios and consequences including operation of containment purge valves, closure times, and leak tightness.

(2) Safety Objective:

To assure that the primary containment isolation provisions meet the requirements of 10 CFR 50, Appendix A, General Design Criteria 54 through 57. Some of the operating plants may have too few or too many isolation provisions. Containment purging during normal operation in PWRs has raised a concern regarding the ability of the ventilation system isolation valves to close upon receipt of an accident signal. The use of resilient sealing materials in conjunction with the cycling of these valves has resulted in an increased degradation in the leakage integrity of the valve seats. To assure the adequacy of the maintenance and repair schedule to maintain the leakage integrity of the valves for the service life of the plant. To assure that containment purge operations will not adversely affect the consequences of postulated accidents.

(3) Status:

The functional performance of the sump lines and emergency core cooling systems is being reviewed in conjunction with the Appendix K submittals. Implementation criteria are being developed to apply the requirements of Branch Technical Position CSB 6-4 to containment purging practices and to improve the leakage integrity of ventilation system isolation valves.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 54 through 57
2. Standard Review Plan, Section 6.4.2
3. Standard Review Plan, Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations"

TOPIC: VI-5 Combustible Gas Control

(1) Definition:

Review the combustible gas control system to determine the capability of the system to monitor the combustible gas concentration in the containment, to mix combustible gases within the containment atmosphere, and to maintain combustible gas concentrations below the combustion limits (for example, by recombination, dilution, or purging). For facilities which share recombiners (portable) between units or sites, determine that the recombiners can be made available within a suitable time. For facilities which utilize purging as a primary means of combustible gas control, determine the radiological consequences of the system operation. Reevaluate hydrogen production and accumulation analysis to consider (1) reduction of Zr/water reaction on the basis of five times the Appendix K calculation amount and (2) potential increases in hydrogen production from corrosion of metals inside containment.

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(2) Safety Objective:

To prevent the formation of combustible gas explosive concentrations in the containment or in localized regions within containment, following a postulated accident; to assure that the radiological consequences of the system operation are acceptable.

(3) Status:

Proposed 10 CFR 50.44 would permit a BWR licensee to propose an alternate combustible gas control system in lieu of inerting. Four such proposals for containment atmosphere dilution systems are currently under review, and the COGAP II computer code is being revised to perform the system evaluations.

(4) References:

1. Proposed rule 10 CFR Part 50, Section 50.44
2. Division of Operating Reactors, DOR Technical Activities, Category A, Item 8, "Containment Purge During Normal Operation," April 1977
3. Division of Operating Reactors, DOR Technical Activities, Category A, Item 14, "Inerting Requirements/CAD," April 1977
4. Standard Review Plan, Branch Technical Position CSB 6-2, "Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident"
5. Standard Review Plan, Section 6.2.5

(5) Basis for Deletion (Related TMI TASK, USI, or Other SEP Topic):

(a) TMI Action Plan Task II.B.7, "Analysis of Hydrogen Control" (NUREG-0660)

As a result of TMI Task II.B.7, short- and long-term rulemaking to amend 10 CFR 50.44 has been initiated. The short-term rulemaking (interim rule) requires that all Mark I and Mark II containments be inerted. It also requires that the owners of all plants with other containments perform certain analyses of accident scenarios involving hydrogen releases and furnish the staff with a proposed approach for mitigating these hydrogen releases.

The longer-term rulemaking will address both degraded core and melted core issues. In the area of hydrogen control, it will prescribe requirements that are appropriate for operating plants as well as for plants under construction.

(b) USI A-48, "Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment" (NUREG-0705)

Under USI A-48, a Task Action Plan has been defined and is being developed that encompasses the concerns in the Definition and the Safety Objective of SEP Topic VI-5.

The evaluation required by TMI II.B.7 and USI A-48 is identical to SEP Topic VI-5; therefore, this SEP topic has been deleted.

TOPIC: VI-6 Containment Leak Testing

(1) Definition:

Certain requirements of primary reactor containment leakage testing for water-cooled power reactors as described in Appendix J to 10 CFR Part 50 (issued February 1973) have been found to be conflicting, impractical for implementation, or subject to a variety of interpretations. Review the primary reactor containment leak testing program for operating nuclear plants.

(2) Safety Objective:

To assure that the containment leak testing program provides a conservative assessment of the leakage rate through individual leakage barriers and to assure that proper maintenance and repairs are conducted during the service life of the containment. The testing acceptance criteria are established to ensure that containment leakage following a postulated accident will not result in offsite doses exceeding 10 CFR 100 guidelines.

(3) Status:

A generic review for compliance with Appendix J and the review of requested exemptions to the regulation is currently underway. Proposed revisions to Appendix J to improve the testing requirements are under development.

(4) References:

1. 10 CFR Part 50, Appendix J
2. 10 CFR Part 50, Appendix A, GDC 52 and 53
3. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-10, "Containment Leak Testing - Appendix J," April 1977
4. Division of Operating Reactors, DOR Technical Activities, Category B, Item 33, "Containment Leak Testing Requirements," May 1977
5. Division of Systems Safety, DSS Technical Activities, Category A, Item 30, "Containment Leak Testing," April 1977

TOPIC: VI-7.A.1 Emergency Core Cooling System Reevaluation To Account for Increased Reactor Vessel Upper Head Temperature

(1) Definition:

Loss-of-coolant accident (LOCA) analyses for all Westinghouse reactors were conducted assuming that the water in the upper head region of the reactor vessel was the same as the inlet water temperature because of a bypass flow from the downcomer to the upper head. Temperature measurements made by Westinghouse indicate that the actual temperature of the upper head fluid exceeds cold leg temperature by 50 to 75% of the difference between hot leg and cold leg (inlet) temperature. All operating reactors were required to resubmit LOCA analyses using hot leg temperature for the upper head volume.

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(2) Safety Objective:

To provide revised LOCA analyses with correct upper head temperatures to assure that peak clad temperature limits are not exceeded.

(3) Status:

Revised analyses have been received from all Westinghouse plants. All but three have been reviewed and approved.

TOPIC: VI-7.A.2 Upper Plenum Injection

(1) Definition:

Emergency core cooling system (ECCS) evaluation of Westinghouse two-loop plants was performed assuming that low pressure pumped injection is delivered directly to the lower plenum. However, ECC coolant is delivered directly into the upper plenum. Interaction of the cold injection water with the steam exiting from the core during refill and reflood and the heat transfer effects during the downward passage to the lower plenum have not been adequately considered.

(2) Safety Objective:

To provide assurance that existing analyses with Westinghouse two-loop plants are acceptable either by showing that the present analyses are conservative, or by developing a new ECCS model which considers upper plenum injection.

(3) Status:

The staff met with the licensees and Westinghouse on January 11 and 26, 1977. The staff requested that the licensees formally submit the information presented at the January 26, 1977 meeting. Two Westinghouse reports have been received to date. The staff is continuing to evaluate the problem. Research requested by the Office of Nuclear Reactor Regulation and performed by the Office of Nuclear Regulatory Research in the semiscale facility provided basis for evaluation.

TOPIC: VI-7.A.3 Emergency Core Cooling System Actuation System

(1) Definition:

Review the emergency core cooling system (ECCS) actuation system with respect to the testability of operability and performance of individual active components of the system and of the entire system as a whole under conditions as close to the design condition as practical.

(2) Safety Objective:

To assure that all ECCS components (for example, valves and pumps) are included in the component and system test. To assure that the frequency and scope of the periodic testing are adequate and meet the requirements of General Design Criterion 37.

(3) Status:

New applications (construction permit and operating license) are reviewed in accordance with the Standard Review Plan and the references listed below. No specific activity for operating reactors is in progress.

(4) References:

1. Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Function"
2. Standard Review Plan, Branch Technical Position EICSB-25, "Guidance for the Interpretation of General Design Criterion 37 for Testing the Operability of the Emergency Core Cooling System as a Whole"
3. 10 CFR Part 50, Appendix A, GDC 37

TOPIC: VI-7.A.4 Core Spray Nozzle Effectiveness

(1) Definition:

Core spray systems are designed with a nozzle or a set of nozzles arranged above the core in such a way that, following a LOCA, a spray of water will be distributed over the top of the core so that each fuel bundle will receive a specified minimum flow which will provide adequate core cooling. Recent test data for a single nozzle in a steam environment noted partial or complete collapse of the spray cone and/or a shift in the direction of spray. These effects were not included in earlier full scale spray tests in air.

(2) Safety Objective:

To assure adequate spray cooling following a LOCA.

(3) Status:

The NRC has reviewed and accepted spray system performance for multiple nozzle spray systems, but has not accepted spray systems with a single overhead spray nozzle. Recent tests in Florida on the Big Rock Point spray nozzle indicate incomplete core coverage. As a result of these tests, NRC is requesting further testing by GE of multiple spray nozzles.

(4) References:

1. Letter from K. Goller, NRC, to operating reactor branch chiefs, Subject: "Generic Issue - Effects of Steam Environment on Core Spray Distribution for Non-jet Pump BWRs," December 7, 1976
2. General Electric, GE Topical Report NEDO-10846, "BWR Core Spray Distribution"

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TOPIC: VI-7.B Engineered Safety Feature Switchover From Injection to Recirculation Mode (Automatic Emergency Core Cooling System Realignment)

(1) Definition:

Most PWRs require operator action to realign emergency core cooling (ECC) systems for the recirculation mode following a LOCA.

We have been requiring, on an ad hoc basis, some automatic features to realign the ECCS from the injection to the recirculation mode of operation.

(2) Safety Objective:

To increase the reliability of long-term core cooling by not requiring operator action to change system realignment to the recirculation mode.

(3) Status:

A draft Branch Technical Position has been prepared which covers both ECC and containment spray systems. The proposed position is awaiting review by the Regulatory Requirements Review Committee.

(4) Reference:

American National Standards Institute, Draft ANSI Standard N 660, "Proposed American National Standard Criteria for Safety-Related Operator Actions"

TOPIC: VI-7.C Emergency Core Cooling System (ECCS) Single-Failure Criterion and Requirements for Locking Out Power to Valves, Including Independence of Interlocks on ECCS Valves

(1) Definition:

The physical locking out of electrical sources to specific motor-operated valves required for the engineered safety functions of ECCS has been required, based on the assumption that a spurious electrical signal at an inopportune time could activate the valves to the adverse position; for example, closed rather than open, or opened rather than closed. There is some concern that interlock circuitry on ECCS valves may not be independent such that a single failure of an interlock due to equipment malfunction or operator error could defeat more than one interlock and cause the valves to be cycled to the wrong position.

(2) Safety Objective:

To ensure that all power-operated valves which could affect emergency core cooling (ECC) system performance by being in the wrong position have power removed except when in use. This will ensure that ECC systems are not defeated by having a valve in the wrong position.

(3) Status:

The staff plans to reconsider EICSB BTP-18 and RSB BTP-6-1.

TOPIC: VI-7.C.1 Appendix K--Electrical Instrumentation and Control Re-reviews

(1) Definition:

During the Appendix K reviews of some facilities initially considered, a detailed electrical instrumentation and control review was not performed. Re-review the modified ECCS of these facilities to confirm that it is designed to meet the most limiting single failure.

(2) Safety Objective:

To assure that the modified ECCS is designed to meet the most limiting (design basis) single failure.

(3) Status:

No current activity in the Division of Operating Reactors.

(4) References:

1. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems"
2. Institute of Electrical and Electronics Engineers, IEEE Std. 308, "Standard Criteria for Class IE Electric Systems for Nuclear Power Generating Stations"

TOPIC: VI-7.C.2 Failure Mode Analysis (Emergency Core Cooling System)

(1) Definition:

Failure modes and effects criticality analyses (FMECA) would be conducted for the purpose of systematically determining potential single failures in emergency core cooling (ECC) systems.

(2) Safety Objective:

To determine if single failures exist in ECC system as an aid in assessing overall plant safety.

(3) Status:

FMECAs have been conducted on the hydraulic portion of ECC systems of representative plant types. In addition, single-failure analyses were performed on each plant as a part of the required Appendix K analysis except for those plants with stainless steel clad cores.

TOPIC: VI-7.C.3 Effect of PWR Loop Isolation Valve Closure During a Loss-of-Coolant Accident on Emergency Core Cooling System Performance

(1) Definition:

Some PWRs are equipped with loop isolation valves. The effect of spurious closure of a loop isolation valve during a LOCA has never been analyzed. To ensure emergency core cooling system (ECCS) performance, power in some cases has been removed from loop isolation valves to prohibit spurious closure.

(2) Safety Objective:

To assure that all plants with loop isolation valves have power removed during operation, or that other acceptable measures are taken to preclude inadvertent closing.

(3) Status:

In most cases power has been removed from loop isolation valves, and this is confirmed as part of staff ECCS performance evaluations. This has not been confirmed for all plants with loop isolation valves.

TOPIC: VI-7.D Long-Term Cooling Passive Failures (for example, Flooding of Redundant Components)

(1) Definition:

The General Design Criteria require that the emergency core cooling systems (ECCSs) shall be capable of providing adequate core cooling following a loss-of-coolant accident, assuming a single failure in emergency core cooling systems. The staff assumes the single failure to be either an active failure during the injection phase, or an active or passive failure during the long-term recirculation phase. The physical layouts of engineered safety feature pumps and components on some pressurized water reactors make them vulnerable to flooding that might result from passive failures in system piping. Protection for pipe cracks or ruptures is not required because of the low probability of occurrence during the ECCS recirculation mode.

(2) Safety Objective:

To provide for increased reliability of ECCSs by assuring that passive failures will not cause flooding and failure of ECCS valves and equipment.

(3) Status:

Issue identified by Fluegge in letter to Rowden, October 24, 1976. Staff response was prepared which concluded that "...consideration of this issue does not warrant revisions to any existing licenses or changes in present priority for addressing the treatment of passive failures subsequent to a LOCA. ECCS passive failure criteria being implemented by the staff require considerations of additional leakage but not pipe breaks beyond the initiating LOCA."

(4) Reference:

NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 7, "Passive Failures Following a Loss-of-Coolant Accident," December 1976

TOPIC: VI-7.E Emergency Core Cooling System Sump Design and Test for Recirculation Mode Effectiveness

(1) Definition:

Following a loss-of-coolant accident in a PWR, an emergency core cooling system (ECCS) automatically injects water into the system to maintain core cooling. Initially, water is drawn from a large supply tank. Water discharging from the break and containment spray collects in the containment building sump. When the supply tank has emptied to a predetermined level, the ECCS is switched from the "injection" mode to the "recirculation" mode. Water is then drawn from the containment building sump.

ECCSs are required to operate indefinitely in this mode to provide decay heat removal. Certain flow conditions could occur in the sump, which could cause pump failures. These include entrained air, prerotation or vortexing, and losses leading to deficient net positive suction head.

(2) Safety Objective:

To confirm effective operation of ECCSs in the recirculation mode.

(3) Status:

Confirmation through preoperational testing is now required on all construction permits. Staff has been accepting scaled tests in lieu of preoperational tests at the operating-license stage. Some plants have required modification to achieve vortex control.

(4) Reference:

Regulatory Guide 1.79, "Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors," (paragraph b(2))

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-43, "Containment Emergency Sump Reliability" (NUREG-0510 and NUREG-0660)

The definition of this topic and the references cited are covered by USI A-43. The evaluation for USI A-43 is identical to SEP Topic VI-7E; therefore, this SEP topic has been deleted.

TOPIC: VI-7.F Accumulator Isolation Valves Power and Control System Design

(1) Definition:

For many loss-of-coolant accidents, the performance of the ECCS in PWR plants depends upon the proper functioning of the accumulators. The motor-operated isolation valve, provided between the accumulator and the primary system, must be considered to be "operating bypass" (IEEE 279-1971) because, when closed, it prevents the accumulator from performing the intended protective function. The motor-operated isolation valve should be designed against a single failure that can result in a loss of capability to perform a safety function.

(2) Safety Objective:

To assure that the accumulator isolation valve meets the "operation bypass" requirements of IEEE 279-1971, which states that the bypass of a protective function will be removed automatically whenever permissive conditions are not met. To assure that a single failure in the electrical system or single operator error cannot result in the loss of capability of an accumulator to perform its safety function.

(3) Status:

Staff positions listed below are implemented on new applications. No systematic review program for operating reactors exists.

(4) References:

1. Institute of Electrical and Electronics Engineers, IEEE Std. 279-1971, "Criteria for Protection System for Nuclear Power Generating Stations"
2. Standard Review Plan, Branch Technical Position EICSB-4, "Requirements on Motor-Operated Valves in the ECCS Accumulator Lines"
3. Standard Review Plan, Branch Technical Position EICSB-18, "Application of Single Failure Criteria to Manually-Controlled Electrically Operated Valves"

TOPIC: VI-8 Control Room Habitability

(1) Definition:

Control rooms in operating plants may not fully comply with General Design Criterion 19. This review should include, but not be limited to, analysis of the control room air infiltration rate, ventilation system isolability and filter efficiency, shielding, emergency breathing apparatus, short distance atmospheric dispersion, operator radiation exposure, and onsite toxic gas storage proximity.

(2) Safety Objective:

To assure that the plant operators can safely remain in the control room to manipulate the plant controls after an accident.

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(3) Status:

The Division of Operating Reactors now reviews control room habitability in operating plants when related licensing actions (for example, assessment of BWR containment air dilution system post-LOCA radiological impact) require it. The Division of Site Safety and Environmental Analysis has a technical assistance contract with the National Bureau of Standards to measure the control room air infiltration rate at a few operating plants. These measurements will be used to gauge the conservatism of the assumed air infiltration rates currently used by NRC. Some reviews are now in progress for plants we have reason to believe do not meet General Design Criterion 19 (San Onofre Nuclear Generating Station Unit 1, Vermont Yankee, St. Lucie).

(4) References:

1. Standard Review Plan, Section 6.4
2. 10 CFR Part 50, Appendix A, GDC 19
3. Murphy, K. G., and K. M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Criterion 19," in *Proceedings of the Thirteenth AEC Air Cleaning Conference*, August 1974
4. Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release"
5. Regulatory Guide 1.95, Rev. 1, "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release"

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- TMI Action Plan Task III.D.3.4, "Control Room Habitability Requirements" (NUREG-0737)

  The review criteria required by Task III.D.3.4 (NUREG-0737, pp. 3-197) are identical to the review criteria specified in the Definition and References of SEP Topic VI-8; therefore, this SEP topic has been deleted.

TOPIC: VI-9 Main Steam Line Isolation Seal System (BWR)

(1) Definition:

Operating experience has indicated that there is a relatively high failure rate and variety of failure modes for components of the main steam isolation valve leakage control system in certain operating BWRs.

(2) Safety Objective:

To assure that leakage rate limits are not exceeded and the resulting calculated offsite doses do not exceed 10 CFR Part 100 guidelines using the [illegible] assumptions.

(3) Status:

Experience from surveillance testing as reported in recent licensee event reports is compiled by the Division of Operating Reactors to serve as a basis for identifying design improvements and for preparing recommendations for future revisions to Regulatory Guide 1.96.

(4) References:

1. Division of Operating Reactors, DOR Technical Activities, Category B, "Main Steam Line Leakage Control System," May 1977
2. Regulatory Guide 1.96, "Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants"
3. Standard Review Plan, Section 6.7

TOPIC: VI-10.A Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing

(1) Definition:

Review the reactor trip system (RTS) and engineered safety features (ESF) test program to verify RTS and ESF operability on a periodic basis and to verify RTS and ESF response time.

(2) Safety Objective:

To assure the operability of the RTS and ESF, on a periodic basis, including verification of sensor response times. To ensure that the RTS and ESF test program demonstrates a high degree of availability of the systems and the response times assumed in the accident analyses are within the design specifications.

(3) Status:

The test program of the RTS and ESF of new license applications is reviewed in accordance with the Standard Review Plan, including applicable Branch Technical Positions. Some licensees have agreed to perform response-time measurements. Operability testing is probably performed, in one form or another, for most licensees of operating reactors.

(4) References:

1. Standard Review Plan, Branch Technical Position EICSB-24, "Testing of Reactor Trip System and Engineered Safety Feature Actuation System Sensor Response Times"
2. Memorandum from V. Stello, NRC, to V. A. Moore, Subject: "GESSAR Second Round of Questions No. 2 and No. 9," October 12, 1973
3. Regulatory Guides
   1.22, "Periodic Testing of Protection System Actuation Functions"
   1.105, "Instrument Setpoints"
   1.118, "Periodic Testing of Electric Power and Protection Systems"

TOPIC: VI-10.B Shared Engineered Safety Features, Onsite Emergency Power, and Service Systems for Multiple Unit Stations

(1) **Definition**:

The sharing of engineered safety features (ESF) systems, including onsite emergency power systems, and service systems for a multiple-unit facility can result in a reduction of the number and of the capacity of onsite systems to below that which normally is provided for the same number of units located at separate sites. Review these shared systems for multiple-unit stations.

(2) **Safety Objective**:

To assure that: (1) the interconnection of ESF, onsite emergency power, and service systems between different units is not such that a failure, maintenance, or testing operation in one unit will affect the accomplishment of the protection function of the systems(s) in other units; (2) the required coordination between unit operators can cope with an incident in one unit and safe shutdown of the remaining units(s); and (3) system overload conditions will not arise as a consequence of an accident in one unit coincident with a spurious accident signal or any other single failure in another unit.

(3) **Status**:

A systematic review of shared ESF, onsite emergency power, and service systems for operating multiple-unit stations is not being conducted. The EICSB Branch Technical Position is applied in the review of new licensee applications.

(4) **References**:

1. Standard Review Plan, Branch Technical Position EICSB-7, "Shared Onsite Emergency Electric Power Systems for Multi-Unit Stations"
2. Regulatory Guide 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants"

TOPIC: VII-1.A Isolation of Reactor Protection System From Nonsafety Systems, Including Qualification of Isolation Devices

(1) **Definition**:

Nonsafety systems generally receive control signals from the reactor protection system (RPS) sensor current loops. The nonsafety sensor circuits are required to have isolation devices to ensure the independence of the RPS channels. Requirements for the design and qualification of isolation devices are quite specific. Recent operating experience has shown that some of the earlier isolation devices or arrangements at operating plants may not be effective.

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(2) Safety Objective:

To verify that operating reactors have RPS designs which provide effective and qualified isolation of nonsafety systems from safety systems to assure that safety systems will function as required.

(3) Status:

A limited generic review of isolation devices is being performed by the Division of Operating Reactors as part of a followup on LER No. 76-42/IT for Calvert Cliffs Unit 1 (TAC 6696). This limited generic review should be complete by August 1, 1977.

(4) References:

1. Licensee Event Report No. 76-42/IT, Calvert Cliffs Unit 1 (Technical Assignment Control (TAC) No. 6696)
2. Standard Review Plan, Section 7.2

TOPIC: VII-1.B Trip Uncertainty and Setpoint Analysis Review of Operating Data Base

(1) Definition:

As a result of Issue No. 13 in NUREG-0138 (Ref. 1) the staff is conducting a survey of plants at the operating-license stage of review to more specifically identify the margin between actual allowable trip parameter limits (from safety analyses standpoint) and actual reactor protection system (RPS) setpoints specified in the Technical Specifications. To clearly identify the setpoint margins, both the ultimate allowable and the specified nominal setting will be identified in the Technical Specifications.

(2) Safety Objective:

To assure that the margins between the allowable trip parameters and the actual RPS setpoints are adequate and properly identified.

(3) Status:

Implementation letters have been sent to the current applicants for operating licenses. The Technical Specifications for operating reactors are only being changed to include both values if a particular plant is converting to Standard Technical Specifications.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 13, "Instrument Trip Setpoints in Standard Technical Specifications," November 1976
2. Memorandum from V. Stello, NRC, to R. Boyd, Subject: "Instrument Trip Setpoint Values," February 18, 1977

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3. Division of Operating Reactors, DOR Technical Activities, Category B, Item 29, "Instrument Trip Setpoints on Standard Technical Specifications," May 1977

TOPIC: VII-2 Engineered Safety Features System Control Logic and Design

(1) Definition:

During the staff review of the safety injection system (SIS) reset issue (Ref. 1) the staff determined that the engineered safety features actuation systems (ESFASs) at both PWRs and BWRs may have design features that raise questions about the independence of redundant channels, the interaction of reset features and individual equipment controls, and the interaction of the ESFAS logic that controls transfers between onsite and offsite power sources. Review the as-built logic diagrams and schematics, operator action required to supplement the ESFAS automatic actions, the startup and surveillance testing procedures for demonstrating ESFAS performance.

Several specific concerns exist with regard to the manual SIS reset feature following a LOCA: (1) If a loss of offsite power occurs after reset, operator action would be required to remove normal shutdown cooling loads from the emergency bus and reestablish emergency cooling loads. Time would be critical if the loss of offsite power occurred within a few minutes following a LOCA. (2) If loss of offsite power occurs after reset, some plants may not restart some essential loads such as diesel cooling water. (3) The plant may suffer a loss of ECCS delivery for some time period before emergency power picks up the ECCS system.

Review the ESF system control logic and design, including bypasses, reset features, and interactions with transfers between onsite and offsite power sources.

(2) Safety Objective:

To assure that the ESFASs are designed and installed so that the necessary automatic control of engineered safety features equipment can be accomplished when required.

(3) Status:

A review of ESFASs of operating PWRs is being performed by the Division of Operating Reactors as part of the followup action to Reference 1 (to be completed end of 1977).

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 4, "Loss of Offsite Power Subsequent to Manual Safety Injection Reset Following a LOCA," November 1976
2. Division of Operating Reactors, DOR Technical Activities Category A, Item 22, "Loss of Offsite Power Subsequent to Manual Reset," April 1972

3. Regulatory Guide 1.41, "Preoperational Testing of Redundant Onsite Electric Power Systems To Verify Proper Load Group Assignments"

TOPIC: VII-3 Systems Required for Safe Shutdown

(1) Definition:

Review plant systems that are needed to achieve and maintain a safe shutdown condition of the plant, including the capability for prompt hot shutdown of the reactor from outside the control room. Included also, a review of the design capability and method of bringing a PWR from a high-pressure condition to low-pressure cooling assuming the use of only safety-grade equipment.

(2) Safety Objective:

(1) To assure the design adequacy of the safe shutdown system to (i) initiate automatically the operation of appropriate systems, including the reactivity control systems, such that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences or postulated accidents and (ii) initiate the operation of systems and components required to bring the plant to a safe shutdown.

(2) To assure that the required systems and equipment, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown are located at appropriate locations outside the control room and have a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

(3) To assure that only safety-grade equipment is required for a PWR plant to bring the reactor coolant system from a high-pressure condition to a low-pressure cooling condition.

(3) Status:

A survey of remote shutdown capability of operating plants was performed some time ago by the Division of Operating Reactors. A technical activity has been proposed by the Division of Project Management (see reference below) regarding safety objective (3). No other activities are in progress.

(4) Reference:

Division of Project Management, DPM Technical Activities, Category A, Item 7, "Isolating Low Pressure Systems Connected to the RCPB," April 1977

TOPIC: VII-4 Effects of Failure in Nonsafety-Related Systems on Selected Engineered Safety Features

(1) Definition:

Potential combinations of transients and accidents with failures of nonsafety-related control systems were not specifically evaluated in the original safety analysis of currently operating reactor plants. Review

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the effects of control system malfunctions as initiating events for anticipated transients and also as failures concurrent with or subsequent to anticipated events or postulated accidents initiated by a different malfunction (for example, the effect of the loss of the plant air system on the plant control and monitoring system). A complete discussion is provided in Reference 1.

(2) Safety Objective:

To assure that any credible combination of a nonsafety-related system failure with a postulated transient or accident will not cause unacceptable consequences.

(3) Status:

A technical assistance contract with Oak Ridge National Laboratory for failure mode analyses of control systems was initiated to determine sensitive areas of the plant designs. The results of this program in conjunction with the results of the failure mode and effects analyses for transients and accidents being performed under contract by Idaho Nuclear Engineering Laboratory should provide a basis for any new review and safety requirements.

(4) References:

1. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum from Director, NRR, to NRR Staff," Issue 22, "Systematic Review of Normal Plant Operation and Control System Failures," December 1976
2. Memorandum from V. Stello, NRC, to R. J. Hart, December 23, 1976, NRR letter No. 46.
3. Division of Operating Reactors, DOR Task Force Report on SEP, Appendix B (TFL 118), November 1976
   a. Item 33, "Safety Related Control Power"
   b. Item 34, "Safety Related Instrumentation Power"
   c. Item 56, "Effect of Failure in Non-Safety Related Systems During Design Basis Events"
   d. Item 57, "Loss of Plant Air System (Effect on Plant Control and Monitoring)"
   e. Item 77, "Safety Related Control and Instrument Power"
4. Directorate of Operational Technology, DOT Recommended List of SEP Subjects, C DOT 102, Item 100z, "Loss of Plant Air System (Effect on Plant Control and Monitoring)," Spring 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-47, "Safety Implications of Control System" (NUREG-0705 and NUREG-0606)

The issue defined in Reference 1 (NUREG-0153, Item 22) is as follows:

> In evaluating plant safety, the effects of control system malfunctions should be reviewed as initiating events for

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> anticipated transients and also as failures that could occur concurrently subsequent to postulated anticipated events (initiated by a different malfunction) or postulated accidents.

The issue defined in USI A-47 is, in part, as follows:

> This issue concerns the potential for transients or accidents being made more severe as a result of the failure or malfunction of control systems. These failures or malfunctions may occur independently, or as a result of the accident or transient under consideration.

(b) USI A-17, "Systems Interactions in Nuclear Power Plants" (NUREG-0649 and NUREG-0606)

The purpose of this task is to develop a method for conducting a disciplined and systematic review of nuclear power plant systems, for both process function couplings of systems and space couplings, to identify the potential sources and types of systems interactions that are determined to be potentially adverse.

A report has been developed, "Final Report - Phase 1 Systems Interaction Methodology Applications Program," NUREG/CR-1321, SAND 80-0384, whose objectives are:

1. To develop a methodology for conducting a disciplined and systematic review of nuclear power plant systems which facilitates identification and evaluation of systems interactions that affect the likelihood of core damage.

2. To use the methodology to assess the Standard Review Plan to determine the completeness of the plan in identifying and evaluating a limited range of systems interactions.

The work done under USI A-17 may be useful in the development of USI A-47.

The Definition of USI A-47 is identical to that of Topic VII-4; therefore, this SEP topic has been deleted.

TOPIC: VII-5 Instruments for Monitoring Radiation and Process Variables During Accidents

(1) Definition:

The adequacy of the instruments for monitoring radiation and process variables during accidents has not been reviewed for conformance with Regulatory Guide 1.97. A generic review is planned to assess the licensee's existing or proposed monitoring instruments during and following accidents to determine the adequacy of their range, response, and qualifications, and to determine the sufficiency of the variables to be monitored. Certain instruments to monitor conditions beyond the design basis accidents will also be required in accordance with an Regulatory Requirements Review Committee (RRRC) determination (Reference 3).

(2) Safety Objective:

To assure that plant operators and emergency response personnel have available sufficient information on plant conditions and radiological releases to determine appropriate in-plant and offsite actions throughout the course of any accident. The instrumentation should also provide recorded transient or trend information necessary for postaccident evaluation of the event. The ability to follow the course of accidents beyond the design basis accidents is also required.

(3) Status:

Generic review of instrumentation to follow the course of accidents in operating plants and in all plants now under construction or seeking a construction permit will begin with the issuance of Regulatory Guide 1.97, Revision 1, this year. Submittals describing the facilities' postaccident instrumentation will be obtained from all operating licensees and reviewed by the end of 1978. The implementation of Regulatory Guide 1.97, Revision 1 on operating plants is proceeding independent of the SEP. The Regulatory Requirements Review Committee has determined that Revision 1 to Regulatory Guide 1.97 should be treated as a Category 2 item (backfit on operating plants on a case-by-case basis).

(4) References:

1. Memorandum from H. G. Mangelsdorf (ACRS) to L. M. Muntzing (Regulations), August 14, 1973
2. Memorandum from L. M. Muntzing (Regulation) to H. G. Mangelsdorf (ACRS), November 1, 1973
3. Memorandum from R. B. Minogue (SD) to E. G. Case (NRR), Enclosure, Proposed Revision 1 to Regulatory Guide 1.97, April 4, 1977
4. Standard Review Plan, Section 7.5
5. Standard Review Plan, Section 7.6
6. Standard Review Plan, Section 11.5
7. Memorandum from T. A. Ippolito (EICSB) to Emergency Instrumentation Task Force Members, August 12, 1974
8. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum from Director, NRR, to NRR Staff," Issue 21, "Instruments for Monitoring Both Radiation and Process Variable During Accidents," December 1976
9. Minutes of Regulatory Requirements Review Committee meeting, January 28, 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- TMI Action Plan Task II.F, "Instrumentation and Controls" NUREG-0660 and NUREG-0737

There are three subtasks under Task II.F as follows:

(a) II.F.1 - Additional Accident Monitoring Instrumentation

(b) II.F.2 - Identification of and Recovery From Conditions Leading to Inadequate Core Cooling

(c) II.F.3 - Instruments for Monitoring Accident Conditions

Specific positions on the required instrumentation for II.F.1 and II.F.2 are in NUREG-0737 and Regulatory Guide 1.97, Revision 2 (December 1980). Instrumentation need for II.F.3 is also in Regulatory Guide 1.97, Revision 2.

The emphasis of TMI Task II.F is the monitoring of radiation and process variables; guidance for this relies primarily on Regulatory Guide 1.97. This is identical to the review proposed in Topic VII-5; therefore this SEP topic has been deleted.

TOPIC: VII-6 Frequency Decay

(1) Definition:

In an issue of Reference 1 it is stated that the staff should require that a postulated rapid decay of the frequency of the offsite power system be included in the accident analysis and that the result be demonstrated to be acceptable. Alternatively, the reactor coolant pump (RCP) circuit breakers should be designed to protection system criteria and tripped to separate the pump motors from the offsite power system. Rapid decay of the frequency of the offsite power system has the potential for slowing down or breaking the RCP, thereby reducing the coolant flow rates to levels not considered in previous analyses.

(2) Safety Objective:

To assure that the reactor coolant flow rate will not decrease below those assumed for a flywheel coastdown.

(3) Status:

Oak Ridge National Laboratory, under a technical assistance program, is currently reviewing the frequency decay rate and its effects on RCPs. This program should be completed before the end of this year and this issue resolved.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 9, "Frequency Decay," November 1976
2. Division of Operating Reactors, DOR Technical Activities, Category B, Item 27, "Frequency Decay," May 1977

TOPIC: VII-7 Acceptability of Swing Bus Design on BWR-4 Plants

(1) Definition:

The swing bus in the original BWR-4 design was used to provide power from either of two redundant electric sources to the low-pressure coolant injection (LPCI) valves by means of an automatic transfer scheme. A single failure in the transfer circuitry could result in paralleling the two redundant electric power sources, thereby degrading their functional capabilities. Review licensee's swing bus automatic transfer circuitry to verify that it is immune to single failures which could lead to paralleling the two electric power sources.

(2) Safety Objective:

To assure that the swing bus design will not propagate an electrical failure between two redundant power sources due to a single failure in the automatic transfer circuit at the BWR-4 swing bus.

(3) Status:

During the course of generic review for compliance with emergency core cooling system criteria 10 CFR 50.46 and Appendix K, some licensees have elected to modify the LPCI system to take credit for a portion of the LPCI flow. These facilities have replaced the swing bus design with a split bus configuration which complies with the requirements of Regulatory Guide 1.6. Not all facilities required a modification of the LPCI to meet the criteria and have retained the swing bus design.

The issue of the swing bus design was identified in Reference 1 and in addition in a letter from the Advisory Committee on Reactor Safeguards (ACRS) dated December 12, 1976.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 3, "Acceptability of Swing Bus Design of BWR-4 Plants," November 1976
2. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems"
3. 10 CFR Part 50, Appendix A, GDC 17
4. Institute of Electrical and Electronics Engineers, IEEE Std. 308, "Standard Criteria for Class IE Electric Systems for Nuclear Power Generating Stations"

TOPIC: VIII-1.A Potential Equipment Failures Associated With Degraded Grid Voltage

(1) Definition:

A sustained degradation of the offsite power source voltage could result in the loss of capability of redundant safety loads, their control circuitry, and the associated electrical components required to perform safety functions.

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(2) Safety Objective:

To assure that a degradation of the offsite power system will not result in the loss of capability of redundant safety-related equipment and to determine the susceptibility of such equipment to the interaction of onsite and offsite emergency power sources.

(3) Status:

A program plan has been developed which includes a short-term program for the review of the emergency power systems of operating reactors and a long-term program to identify those conditions affecting the offsite power sources which may require that additional safety measures be taken.

(4) References:

1. NUREG-0090-5, "Report to Congress, Abnormal Occurrences at Millstone 2, July-September 1976," March 1977
2. Memorandum from D. G. Eisenhut, NRC, to K. R. Goller, Subject: "Staff Positions (Short-Term Program)," April 20, 1977
3. Letters to licensees, August 12 and 13, 1976
4. Division of Operating Reactors, DOR Technical Activities, Category A, Item 9, "Potential Equipment Failures Associated with a Degraded Off-site Power Source," April 1977

TOPIC: VIII-2 Onsite Emergency Power Systems (Diesel Generator)

(1) Definition:

Diesel generators, which provide emergency standby power for safe reactor shutdown in the event of total loss of offsite power, have experienced a significant number of failures. The failures to date have been attributed to a variety of causes, including failure of the air startup, fuel oil, and combustion air systems. In some instances, the malfunctions were due to lockout. The information available to the control room operator to indicate the operational status of the diesel generator was imprecise and could lead to misinterpretation. This was caused by the sharing of a single annunciator station by alarms that indicate conditions that render a diesel generator unable to respond to an automatic emergency start signal and alarms that only indicate a warning of abnormal, but not disabling, conditions. Another cause was the wording on an annunciator window which did not specifically say that the diesel generator was inoperable (that is, unable at the time to respond to an automatic emergency start signal), when in fact it was inoperable for that purpose. The review includes the qualification, reliability, operation at low loads, lockout, fuel oil, and testing of diesel generators.

(2) Safety Objective:

To assure that the diesel generator meets the availability requirements for providing emergency standby power to the engineered safety features.

(3) Status:

Under a technical assistance request (in preparation), a thorough evaluation of all reported failures, including a comprehensive evaluation of diesel manufacturer and utility procedures for inspection, maintenance, and operation, will be performed. Letters were sent on March 29, 1977 to all the affected licensees requesting additional information about diesel generator status indication in the control room. Our intention is to require that at least one annunciation be provided in the control room which will alarm whenever the diesel generator is unavailable due to any lockout condition.

(4) References:

1. Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants"
2. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-11, "Diesel Generator Lockout," April 1977

TOPIC: VIII-3.A Station Battery Capacity Test Requirements

(1) Definition:

Review the Technical Specification, including the test program, with regard to the requirement for periodic surveillance testing of onsite Class IE batteries and the extent to which the test meets Section 5.3.6 of IEEE Std. 308-1971, to determine battery capacity.

(2) Safety Objective:

To assure that the onsite Class IE battery capacity is adequate to supply dc power to all safety-related loads required by the accident analyses and is verified on a periodic basis. This effort is needed to ensure that the test to determine battery capacity includes (1) an acceptance test of battery capacity performed in accordance with Section 4.1 of IEEE Std. 450-1975; (2) a performance discharge test listed in Table 2 of IEEE Std. 308-1971, performed according to Sections 4.2 and 5.4 of IEEE Std. 450-1975; and (3) a battery service test described in Section 5.6 of IEEE Std. 450-1972, to be performed during each refueling operation.

(3) Status:

The review of station battery capacity test requirements is applicable to all operating reactors. There is no ongoing effort on this subject for operating reactors except for those reactors converting to Standard Technical Specifications.

(4) References:

1. Standard Review Plan, Appendix 7-A, Branch Technical Position EICSB 6
2. Institute of Electrical and Electronics Engineers, IEEE Std. 308-1971, 1974, "Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations"

3. Institute of Electrical and Electronics Engineers, IEEE Std. 450-1975, "Recommanded Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations"
4. Memorandum from J. G. Keppler to R. H. Vollmer, NRC, March 20, 1972
5. Memorandum from V. D. Thomas to R. Carlson, January 18, 1972

TOPIC: VIII-3.B DC Power System Bus Voltage Monitoring and Annunciation

(1) Definition:

Review the dc power system battery, battery charger, and bus voltage monitoring and annunciation design with respect to dc power system operability status indication to the operator. This information is needed so that timely corrective measures can be taken in the event of loss of an emergency dc bus.

(2) Safety Objective:

To assure the design adequacy of the dc power system battery and bus voltage monitoring and annunciation schemes such that the operator can (1) prevent the loss of an emergency dc bus or (2) take timely corrective action in the event of loss of an emergency dc bus.

(3) Status:

The review of the dc power system battery and bus voltage monitoring and annunciation adequacy as it relates to the loss of an emergency dc bus is applicable to all operating reactors. This topic is included in the NRR Technical Activity, "Adequacy of Safety Related DC Power Supplies."

(4) Reference:

Standard Review Plan, Section 8.3.2

TOPIC: VIII-4 Electrical Penetrations of Reactor Containment

(1) Definition:

Review the electrical penetration assembly with respect to the capability to maintain containment integrity during short-circuit current conditions and mechanical integrity during the worst expected fault current vs. time conditions resulting from single random failures of circuit overload protection devices.

(2) Safety Objective:

To assure that all electrical penetrations in the containment structure, whether associated with Class IE circuits or non-Class IE circuits, are designed not to fail from electrical faults during a loss-of-coolant accident.

(3) Status:

The subject of electrical cable penetrations was identified in Reference 1 and has been proposed as a Technical Activity Category A item by the Division of Systems Safety (Reference 2). The purpose of that activity is a reevaluation of the penetrations to clarify and augment the design safety margin.

(4) References:

1. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue 18, "Electrical Cable Penetration of Reactor Containment," December 1976
2. Division of Systems Safety, DSS Technical Activity, Category A, Item 36, "Electrical Cable Penetrations of Reactor Containment," April 1977
3. Regulatory Guide 1.63, "Electric Pentration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants"
4. Institute of Electrical and Electronics Engineers, IEEE Std. 317-1976, "Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations"

TOPIC: IX-1 Fuel Storage

(1) Definition

Review the storage facility for new and irradiated fuel, including the cooling capability and seismic classification of the fuel pool cooling system of the spent fuel storage pool. Specifically review the expansion of the onsite spent fuel storage capacity, including the structural response of the fuel storage pool and the racks, the criticality analysis for the increased number of stored fuel assemblies at reduced spacing, and the capability of the spent fuel cooling system to remove the additional heat load.

(2) Safety Objective:

To assure that new and irradiated fuel is stored safely with respect to criticality ($k_{eff} < 0.95$), cooling capability (outlet temperature < 150°F), shielding, and structural capability.

(3) Status:

Approximately two-thirds of the operating reactor plants have requested authorization to increase the storage capacity of their fuel storage pool. The applications are reviewed on a case-by-case basis. New or modified storage rack designs are reviewed against current design criteria; however, the existing pool structure is based on original design criteria.

(4) References

1. Division of Operating Reactors, DOR Technical Activities, Category A, Item 27, "Increase in Spent Fuel Storage Capacity," April 1977
2. American National Standards Institute, ANSI-210, "Design Objectives for Spent Fuel Storage Facilities"

TOPIC: IX-2 Overhead Handling Systems (Cranes)

(1) Definition:

Overhead handling systems (cranes) are used to lift heavy objects in the vicinity of PWR and BWR spent fuel storage facilities and inside the reactor building. If a heavy object (for example, a shielded cask) were to drop on the spent fuel or on the reactor core during refueling, there could be a potential for overexposure of plant personnel and for release of radioactivity to the environment. Review the overhead handling system, including sling and other lifting devices, and the potential for the drop of a heavy object on spent fuel, including structural effects.

(2) Safety Objective:

To assess the safety margins, and improve margins where necessary, of the overhead handling systems to assure that the potential for dropping a heavy object on spent fuel is within acceptable limits and that the potential radiation dose to an individual does not exceed the guidelines of 10 CFR Part 100.

(3) Status:

Regulatory Guide 1.104, "Overhead Crane Handling Systems for Nuclear Power Plants," was issued for comment in February 1976 and references various industry standards. New applications (construction permit and operating license) are reviewed in accordance with APCSB Branch Technical Position 9-1 which is identical to Regulatory Guide 1.104.

The review of overhead handling systems of operating reactor facilities is performed on a generic basis and has also been identified as a DOR Technical Activity Category A.

4) References:

1. Regulatory Guide 1.104, "Overhead Crane Handling Systems for Nuclear Power Plants"
2. Standard Review Plan, Branch Technical Position APCSB 9-1, "Overhead Handling Systems for Nuclear Power Plants"
3. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-22, "Fuel Cask Drop Analysis," April 1977
4. Division of Operating Reactors, DOR Technical Activities, Category A, Item 50, "Control of Heavy Loads Over Spent Fuel," April 1977

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(5) Basis for Deletion (Related TMI Task, USI or Other SEP Topic):

USI A-36, "Control of Heavy Loads Near Spent Fuel" (NUREG-0649)

The review criteria required by USI A-36 (Standard Review Plan, Section 9.1.4, and NUREG-0554) are identical to the review criteria specified in the References of SEP Topic IX-2 (BTP 9-1 and Regulatory Guide 1.104); therefore, this SEP topic has been deleted.

TOPIC: IX-3 Station Service and Cooling Water Systems

(1) Definition:

Review the station service water and cooling water systems that are required for safe shutdown during normal, operational transient, and accident conditions, and for mitigating the consequences of an accident or preventing the occurence of an accident. These include cooling water systems for reactor system components (components cooling water system), reactor shutdown equipment, ventilation equipment, and components of the emergency core cooling system (ECCS). These systems also include the station service water system, the ultimate heat sink, and the interaction of all the above systems.

The review of these systems includes the pumps, heat exchangers, valves and piping, expansion tanks, makeup piping, and points of connection or interfaces with other systems. Emphasis is placed on the cooling systems for safety-related components such as ECCS equipment, ventilation equipment, and reactor shutdown equipment.

The following specific aspects of those systems will be considered in the review:

(a) Physical separation of redundant cooling water systems that are vital to the performance of engineered safety systems components,

(b) Availability of cooling water to primary reactor coolant pumps,

(c) Requirements for makeup water of cooling water systems,

(d) Effect of water overflow from tanks,

(e) Circulating water system barrier failure protection.

(2) Safety Objective:

To assure that the station service and cooling water systems have the capability, with adequate margin, to meet their design objective. To assure, in particular, that

(a) Systems are provided with adequate physical separation such that there are no adverse interactions among those systems under any mode of operation;

(b) Cooling water is provided to the bearings of the primary reactor coolant pumps by two independent essential service water systems for PWR plants to take credit for core cooling by pump coastdown. In addition, it should be demonstrated that the possibility of simultaneous loss of water in both essential service water systems by valve closure is sufficiently small;

(c) Sufficient cooling water inventory has been provided or that adequate provisions for makeup are available;

(d) Tank overflow cannot be released to the environment without monitoring and unless the level of radioactivity is within acceptable limits;

(e) Vital equipment necessary for achieving a controlled and safe shutdown is not flooded due to the failure of the main condenser circulating water system.

(3) Status:

The station service and cooling water systems of applications currently under review are evaluated in accordance with the Standard Review Plan (Sections 9.2.2 and 10.4.5). Some of the specific concerns identified above are under generic review or have been proposed for a technical activity in the Office of Nuclear Reactor Regulation in accordance with the references below.

(4) References:

1. Letter from R. F. Fraley (ACRS) to L. V. Gossick, Subject: "Analysis of Systems Interactions," November 1, 1976
2. Memorandum from B. C. Rusche to L. V. Gossick, ACRS Subcommittee on Systems Interactions, January 1977
3. Division of Project Management, DPM Technical Activities, Category A, Item DPM-15, "Systems Interactions in Nuclear Power Plants," April 1977
4. Memorandum to R. L. Tedesco, NRC, to D. B. Vassallo, Auxiliary Systems Branch 02 on Yellow Creek Nuclear Plant, Item 010.42, (cooling water for RCP), January 31, 1977
5. Division of Systems Safety, DSS Technical Safety Activities Report, "Cooling Water System Makeup Water Requirements (For Safety Systems)," December 1975
6. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-20, "Flood of Equipment Important to Safety (Generic)," April 1977
7. Division of Operating Reactors, DOR Technical Activities, Category A, Item 15, "Flood of Equipment Important to Safety," April 1977

TOPIC: IX-4 Boron Addition System (PWR)

(1) Definition:

Review the boron addition system (PWR), in particular with respect to boron precipitation during the long-term cooling mode of operation following a loss-of-coolant accident.

(2) Safety Objective:

To assure that boron precipitation will not impair the operability of valves or components in the boron addition system which could compromise its capability to control core reactivity during the normal, transient, or emergency shutdown conditions or that would result in flow blockage through the core during the long-term core cooling mode following a loss-of-coolant accident.

(3) Status:

Operating PWR reactors, with the exception of the Combustion Engineering reactors, have been reviewed and found to be acceptable in regard to boron precipitation following a loss of coolant. There are still certain outstanding issues that need to be resolved on this issue for Combustion Engineering reactors. In regard to the precipitation of boron in the boron addition system in both BWRs and PWRs, certain older plants may not have been reviewed in sufficient detail to assure that system reliability is adequate.

(4) Reference:

Standard Review Plan, Section 9.3.4

TOPIC: IX-5 Ventilation Systems

(1) Definition:

Review the design and operation of ventilation systems whose function is to maintain a safe environment for plant personnel and engineered safety features equipment. For example, the function of the spent fuel pool area ventilation system is to provide ventilation in the spent fuel pool equipment areas, to permit personnel access, and to control airborne radioactivity in the area during normal operation, anticipated operational transients, and following postulated fuel handling accidents. The function of the engineered safety feature ventilation system is to provide a suitable and controlled environment for engineered safety feature components following certain anticipated transients and design basis accidents.

(2) Safety Objective:

To assure that the ventilation systems have the capability to provide a safe environment, under all modes of operation, for plant personnel (10 CFR Part 20) and for engineered safety features (for example, to assure that

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the diesel room has redundant outside air intakes and removed from the exhaust discharge).

(3) Status:

The ventilation systems of plants under current review (construction permit and operating license applications) are currently evaluated in accordance with the Standard Review Plan. No specific issues or concerns have been identified for operating reactor plants.

(4) References:

Standard Review Plan, Sections 9.4.1 through 9.4.5

TOPIC: IX-6 Fire Protection

(1) Definition:

Review the fire protection program of operating reactor plants to determine whether improvements are required in accordance with the APCSB Technical Position 9.5-1, Appendix A (Reference 2). The fire protection program encompasses the components, procedures, and personnel utilized in carrying out all activities of fire protection and includes such things as fire prevention, detection, annunciation, control, confinement, suppression, extinguishment, administrative procedures, fire brigade organization, inspection and maintenance, training, quality assurance, and testing. The review includes such items as: (1) the use of insulation inside the containment and (2) the consequences of the inadvertent release of hydrogen into the plant.

(2) Safety Objective:

To assure that, in case of a fire within the plant, the integrity of the engineered safety features is not compromised and that the safe shutdown capability and control of the plant are not lost.

(3) Status:

A generic review of fire protection for operating plants is under way. All licensees were requested by letter (May 11, 1976) to submit an evaluation of their fire protection program for that plant in comparison with the APCSB Technical Position 9.5-1. Subsequently, in September 1976, the licensees were provided with Appendix A to the BTP 9.5-1 which presents acceptable alternatives for operating plants.

(4) References:

1. NUREG-0050, "Recommendations Related to Browns Ferry Fire," February 1976
2. Standard Review Plan, Branch Technical Position APCSB 9.5-1, Appendix A, "Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976"

3. Regulatory Guide 1.120, "Fire Protection Guidelines for Nuclear Power Plants"
4. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-18, "Fire Protection," April 1977
5. Division of Operating Reactors, DOR Technical Activities, Category A, Item 28, "Fire Protection," April 1977
6. Division of Systems Safety, DSS Technical Activities, Category A, Item 32, "Fire Protection," April 1977
7. Letter from R. F. Fraley, ACRS, to L. V. Gossick, Subject: "Analysis of Systems Interactions - Item 6," November 1, 1976

TOPIC: X Auxiliary Feedwater System

(1) Definition:

Review the auxiliary feedwater system, associated instrumentation, and connection between redundant systems. The review includes the aspects of pump drive and power supply diversity (for example, electrical and steam-driven sources), and the water supply sources for the auxiliary feedwater system.

(2) Safety Objective:

To assure that the auxiliary feedwater system can provide an adequate supply of cooling water to the steam generators for decay heat removal in the event of a loss of all main feedwater. Older PWR plants may not meet the requirement for pump drive and power supply diversity.

(3) Status:

Reviews for new license applications are performed in accordance with the Standard Review Plan. This topic is not under active review for operating plants.

(4) References:

1. Standard Review Plan, Section 10.4.9
2. Standard Review Plan, Branch Technical Position APCSB 10-1, "Design Guidelines for Auxiliary Feedwater System Pump Drive and Power Supply Diversity for PWR Plants"

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

TMI Action Plan Task II.E.1.1, "Auxiliary Feedwater System Evaluation" (NUREG-0660)

The TMI-2 accident and subsequent investigations and studies highlighted the importance of the auxiliary feedwater (AFW) system in the mitigation of severe transients and accidents. Since then, the AFW systems have come under close scrutiny by the NRC and many improvements have been recommended to enhance the reliability of AFW systems for all plants. The scope of the review outlined in the SEP

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Topic X definition is identical to the scope of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item II.E.1.1(2), which requires that each PWR plant licensee:

> Perform a deterministic review of the AFW system using the acceptance criteria of Standard Review Plan Section 10.4.9 and associated Branch Technical Position ASB 10-1 as principal guidance.

The review criteria for the evaluations required by Item II.E.1.1(2) are identical to SEP Topic X; therefore, this SEP topic has been deleted.

TOPIC: XI-1 Appendix I

(1) Definition:

A generic review of all operating plants to determine their capability to comply with Appendix I, 10 CFR 50, and to prevent explosions in the gaseous radwaste system is currently underway.

(2) Safety Objective:

To provide assurance that radioactive gaseous effluents from the facility can be kept "as low as reasonably achievable" as defined in Appendix I, 10 CFR Part 50, and to assure adequate control of the mixture of gases in the gaseous radwaste system to prevent explosions.

(3) Status:

A generic review of all operating reactors (ORs) for their capability to conform with Appendix I, 10 CFR Part 50, is currently under way by the Division of Site Safety and Environmental Analysis. Upon the completion of this review, new gaseous and liquid radiological effluent and monitoring Technical Specifications will be issued to all ORs. This will include new Technical Specifications on gaseous radwaste systems which may contain explosive gas mixtures to meet present criteria. The estimated completion date of this review is 1979.

(4) References:

1. 10 CFR Part 20
2. 10 CFR Part 50, Appendix I
3. 10 CFR Part 50, Appendix A
4. 10 CFR Part 50, Appendix A, GDC 60, 61, 63, and 64
5. Standard Review Plan, Section 11.3

(5) Basis for Deletion

Topic XI-1 is being resolved by the following NRR generic topics: (a) A-02, "Appendix I" and (b) B-35, "Confirmation of Appendix I Models." Resolution of these two generic topics will primarily result in Technical Specification changes and may require some minor hardware changes. At

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present, nothing more than the addition of monitoring instrumentation is foreseen. The implementation of Appendix I will, therefore, not affect the integrated assessment for SEP plants.

In addition, the implementation of Appendix I will result in limiting conditions for operation to assist licensees in keeping the amount of radioactive material released in effluents to unrestricted areas as low as is reasonably achievable. Since licensees are currently restricted in the types and amounts of effluents they can release, implementation of additional restrictions on releases should not impact operation of the plant.

Based on the above, Topic XI-1 has been deleted from the SEP program.

TOPIC: XI-2 Radiological (Effluent and Process) Monitoring Systems

(1) Definition:

Onsite radiological monitoring systems are used to:

(a) Assess the proper functioning of the process and waste treatment systems,

(b) Assure that radioactive releases do not exceed the appropriate guidelines, and

(c) Measure actual releases to evaluate their environmental impact.

There is concern about the adequacy of radiation monitoring systems. A survey of 12 plants has been initiated. The results of this survey will indicate whether this area needs to be reviewed for all operating plants. Re-review would include the monitor's sensitivity, range, location, and calibration techniques.

(2) Safety Objective:

To provide reasonable assurance that the licensee adequately monitors the releases of radioactive materials in liquid and gaseous effluent and that the releases are properly restricted. To provide assurance that the licensee adequately monitors the operation of equipment that contains or may contain radioactive material.

(3) Status:

A technical assistance program has been initiated at Brookhaven National Laboratory with the scope including the above safety objectives.

(4) References:

1. 10 CFR Part 20, Section 20.106
2. 10 CFR Part 50, Section 50.36a
3. 10 CFR Part 50, Appendix A, GDC 60, 61, 63, and 64
4. 10 CFR Part 50, Appendix I
5. Standard Review Plan, Section 11.5

(5) Basis for Deletion

Topic XI-2 is being resolved by the following NRR generic topics: (a) A-02, "Appendix I" and (b) B-67, "Effluent and Process Monitoring Instrumentation." A-02 is discussed in Topic XI-1. Generic item B-67 was subdivided into four subtasks. The staff believes that events since the inception of B-67 have largely addressed the identified concerns or changed its thinking in regard to their safety significance. The description and bases for deletion of each subtask are presented below.

Subtask 1: Monitoring of Radioactive Materials Released in Effluents

Item III.D.2.1, Radiological Monitoring of Effluents requires an NRR evaluation of modifying effluent monitoring design criteria based on TMI-2 and their experiences.

Item II.F.1(1), Noble Gas Effluent Monitor of Clarification of the TMI Action Plan Requirements (NUREG-0737) is being implemented to require adequate monitoring capability during accident conditions.

Subtask 2: Control of Radioactive Materials Released in Effluents

The purpose of this subtask was to review plant operating histories and prepare NUREG reports documenting the evaluations and recommending solutions to identified problems.

Various staff actions since 1978 (including NUREG reports and IE Bulletins) have resulted in the staff conclusion that no continuing need for additional staff guidance exists.

Subtask 3: Effects of Accidental Liquid Releases on Nearby Water Supplies

The purpose of this task was to perform a generic analysis of the consequences of liquid tank failures for those plants which received their license prior to issuance of the Standard Review Plan (SRP).

Experience in performing SRP analyses for newer plants has indicated that it is highly unlikely that radioactive concentrations in the nearest potable water supply could exceed 10 CFR Part 20 values.

Subtask 4: Performance of Solid Waste Systems

The purpose of subtask 4 was to perform an industry-wide survey to determine the extent to which power plants could process wastes and to develop plans for upgrading existing systems or adding new systems.

The NRC position relative to a requirement for an operable installed solid radwaste system has changed and, therefore, this subtask is no longer appropriate.

For the above reasons, Issue B-67 is being deleted from the NRR list of generic issues. Since Issue B-67 is being deleted, only Generic Issue A-02, "Appendix I" is appropriate to this topic.

The resolution of Issue A-02 is described in the Basis for Deletion for Topic XI-1. Topic XI-2 is being deleted from the SEP program for the same reasons.

TOPIC: XIII-1 Conduct of Operations

(1) Definition:

The organization, administrative controls, and operating experience will be reviewed. The existing organization and administrative controls will be compared with Standard Technical Specifications and guidance provided in Regulatory Guides 1.8 and 1.33 to determine the adequacy of the staff to protect the plant and to operate safely in routine, emergency, and long-term postaccident circumstances. The plant operating history will be reviewed to assess the combination of staff, operating controls and alarms, and administrative controls, in particular plant procedures, emergency planning, and offsite preparedness, to determine whether additional staff, qualifications, or administrative controls will be required for continued safe operation.

(2) Safety Objective:

To obtain reasonable assurance that the plant has enough people, with sufficient training and experience, and has administrative controls adequate to specify proper operation in routine, emergency, and postaccident conditions.

(3) Status:

Most of the older plants have staff members that meet the experience and educational requirements given in ANSI N18.1-1971 (endorsed by Regulatory Guide 1.8); however, a comparison against current criteria for the composite staff has not been made. These plants have provided training for subsequent plant staffs, and plant experience has, in general, demonstrated safe design and operation. Operating experience review is ongoing, and has been, in general, favorable. However, an analysis of this experience for trends, common elements, and potential hidden problems has not been systematically performed.

A review of Section VI of operating reactor licensees' Technical Specifications was begun in 1974 using Section VI of the Standard Technical Specifications (STS) as a model. As of September 1975, these reviews had been completed and the plants licensed prior to this time had been found to: (1) be acceptable and upgrading was not required, (2) require upgrading of only the reporting requirements, or (3) require improvement to be comparable to the STS model. Plants licensed after September 1975 have been reviewed against the STS model. Further review of Section VI, therefore, will not be required.

Emergency plans submitted at the operating-license stage complied with 10 CFR 50, Appendix E, 1970; however, these plans are not consistent with the guidance given in new Regulatory Guide 1.101, Revision 1, 1977.

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(4) References:

1. Regulatory Guides
   1.8, "Personnel Selection and Training"
   1.33, "Quality Assurance Program Requirements (Operations)"
2. American National Standards Institute, ANSI N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel"
3. American National Standards Institute, ANSI N18.7-1972 Revised, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants"
4. Standard Technical Specifications, Section VI
5. 10 CFR Part 50, Appendix E
6. Regulatory Guide 1.101, Rev. 1, "Emergency Planning for Nuclear Power Plants"
7. Standard Review Plan, Section 13.3
8. NUREG 75/111, "Guide and Checklist for Development and Evaluation of State and Local Government Radiological Emergency Response Plans In Support of Fixed Nuclear Facilities," October 1975
9. Environmental Protection Agency, "EPA Manual of Protective Action Guides and Protective Action for Nuclear Incidents," September 1975
10. Memorandum of Understanding, NRR and Office of State Programs on State and Local Preparedness, March 10, 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) TMI Action Plan Task I.C.6, "Procedures for Verification of Correct Performance of Operating Activities," (NUREG-0737)

Under TMI Task I.C.6, a review of licensee procedures will be conducted to assure that an effective system of verifying the correct performance of operating activities exists. The purpose of this review is to provide a means of reducing human errors and improving the quality of normal operation. References cited for this review are ANSI Standard N18.7-1972 (ANS 3.2), "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," and Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)." These are the same references cited for Topic XIII-1.

(b) TMI Action Plan Task III.A.1, "Improve Licensee Emergency Prepared ness - Short-Term," and Task III.A.2, "Improving Licensee Emergency Preparedness - Long-Term" (NUREG-0660 and NUREG-0737)

Under Task III.A.1, a review of 10 CFR Part 50, Appendix E backfit requirements is being conducted in accordance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." The scope of NUREG-0654 covers Standard Review Plan, Section 13.3, and NUREG 75/111.

Regulatory Guide 1.101 has been deleted and has been superseded by an amended Appendix E to 10 CFR Part 50 (45 FR 55410, August 19, 1980). Under Task III.A.2, a review of licensee's emergency preparedness plans with respect to amended Appendix E will be conducted in accordance with NUREG-0654.

The evaluations required by TMI Tasks I.C.6, III.A.1, and III.A.2 are identical to SEP Topic XIII-1; therefore, this SEP topic has been deleted.

TOPIC: XIII-2 Safeguards/Industrial Security

(1) Definition:

Industrial security will be included under the scope of the operations review. Design features to assess the plant's capability to prevent sabotage and protect the operating unit(s) at dual or three-unit sites with unit(s) under construction will be included. Protective measures will be balanced against the sabotage threat. Fuel accountability will also be reviewed to assure that adequate inventory control procedures exist and the required records are kept.

(2) Safety Objective:

To determine that the plant has adequate security forces, design features, procedures and plans, and other administrative controls to meet the postulated sabotage threat. To assure that the fuel is adequately accounted for, that proper records are maintained, and the required reports are made.

(3) Status:

Each licensee currently has a security program and a fuel accountability program. Revised 10 CFR 73.55 has been published and submittals in accordance with its provisions were due May 25, 1977. These submittals are currently being evaluated.

(4) References:

1. 10 CFR Part 70
2. 10 CFR Part 73
3. Standard Technical Specifications, Section VI

TOPIC: XV-1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

(1) Definition:

Review the assumptions, calculational models used and consequences of postulated accidents which involve an unplanned increase in heat removal. An excessive heat removal, that is, a heat removal rate in excess of the heat generation rate in the core, causes a decrease in moderator temperature which increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. If clad failure is calculated to occur, determine that offsite dose consequences are acceptable.

(2) Safety Objective:

To assure that pressures in the reactor coolant and main steam systems are limited in order to protect the reactor coolant pressure boundary from

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overpressurization and that fuel rod cladding failure as a result of departure from nucleate boiling ratio is limited.

(3) Status:

During each reload review by the staff, the previously determined limiting transient is reviewed to determine if new core parameters are more restrictive than the reference analysis parameter values.

(4) References:

Standard Review Plan, Sections 15.1.1 through 15.1.4

TOPIC: XV-2 Spectrum of Steam System Piping Failures Inside and Outside of Containment (PWR)

(1) Definition:

Review the assumptions, including use of nonsafety-grade equipment and concurrent steam generator or tube failure or blowdown of more than one steam generator, calculational models used, and consequences of postulated accidents which cause an increase in steam flow. The excessive steam flow reduces system temperature and pressure which increases core reactivity and can lead to a decrease of shutdown margin and departure from nucleate boiling ratio.

(2) Safety Objective:

To assure that (1) pressure in the reactor coolant and main steam lines is limited in order to protect the reactor coolant pressure boundary from overpressurization, (2) fuel damage is sufficiently limited so that the core will remain in place and intact with no loss of core cooling capability, (3) doses at the nearest exclusion area boundary are a small fraction of 10 CFR Part 100 guidelines, (4) ambient conditions do not exceed equipment qualification conditions (particularly nonsafety-grade equipment used to mitigate the accident), (5) the thermal and stress transients do not damage the reactor vessel, and (6) systems necessary for safe shutdown are not damaged by the accident.

(3) Status:

Investigation of the effects of high-energy line failures outside containment on other equipment was initiated as a generic issue in 1971 and all but a few facilities have been completed. New acceptance criteria have evolved during the review period. There was no similar investigation for failures inside containment. No reviews on operating plants of the effects on the reactor of concurrent steam generator or tube failure, or of blowdown of more than one steam generator have been performed.

(4) Reference:

Standard Review Plan, Section 15.1.5

TOPIC: XV-3 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulatory Failure (Closed)

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated accidents which involve a decrease in secondary heat removal. The decrease in heat removal causes a suddent increase in system pressure and temperature.

(2) Safety Objective:

To assure that pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained.

(3) Status:

The consequences associated with these transients are compared during each reload review to the consequences found to be acceptable during previous reload reviews.

(4) References:

Standard Review Plan, Sections 15.2.1 through 15.2.5

TOPIC: XV-4 Loss of Nonemergency AC Power to the Station Auxiliaries

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated accidents which involve the loss of nonemergency ac power (loss of offsite power or onsite ac distribution system) to station auxiliaries (for example, reactor coolant circulation pumps). This power loss will, within a few seconds, cause the turbine to trip and reactor coolant system to be isolated, which in turn causes the coolant pressure and temperature to increase.

(2) Safety Objective:

To assure that the pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained.

(3) Status:

During each reload review by the staff, the previously determined limiting transient is reviewed to determine if new core parameters are more restrictive than the reference analysis parameter values.

(4) Reference:

Standard Review Plan, Section 15.2.6

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TOPIC: XV-5 Loss of Normal Feedwater Flow

(1) Definition:

Review the assumptions, calculational models used, and consequences of the postulated loss of feedwater flow accidents, which cause an increase in coolant pressure and temperature.

(2) Safety Objective:

To assure that pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained.

(3) Status:

The consequences associated with these transients are compared during each reload review to the consequences found to be acceptable during previous reload reviews.

(4) Reference:

Standard Review Plan, Section 15.2.7

TOPIC: XV-6 Feedwater System Pipe Breaks Inside and Outside Containment (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated accidents which involve feedwater line breaks of different sizes. A feedwater line break, depending on size, may cause reactor system heatup (by reducing feedwater flow to the steam generator), or cooldown (by excessive energy discharge through the break).

(2) Safety Objective:

To assure that pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained and that any radioactivity release would result in doses at the site boundary well within 10 CFR Part 100 guidelines.

(3) Status:

The identification of the most limiting transients and the consequences associated with these transients is evaluated during each reload review by the staff.

(4) Reference:

Standard Review Plan, Section 15.2.8

TOPIC: XV-7 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

(1) Definition:

Review the assumptions, calculational models, and consequences of seizure of the rotor or break of the shaft of a reactor coolant pump in a PWR or recirculation pump in a BWR. These accidents result in a sudden decrease in core coolant flow and corresponding degradation of core heat transfer and, in a PWR, an increase in primary system pressure. If clad failure is calculated, determine that offsite consequences are acceptable.

(2) Safety Objective:

To assure that the consequences of a reactor coolant pump rotor seizure or reactor coolant pump shaft break are acceptable; that is, that no more than a small fraction of the fuel rods fail, that the radiological consequences are a small fraction of 10 CFR Part 100 guidelines, and that the system pressure is limited in order to protect the reactor coolant pressure boundary from overpressurization.

(3) Status:

Reviewed during each reload only if there is reason to believe that results would be different from the reference analysis; that is, only if a change in core parameters invalidates previous analyses.

(4) Reference:

Standard Review Plan, Section 15.3.3

TOPIC: XV-8 Control Rod Misoperation (System Malfunction or Operator Error)*

(1) Definition:

Review the licensee's description of rod position, flux, pressure, and temperature indication systems and the actions initiated by those systems which can mitigate the effects or prevent the occurrence of various misoperations. Review the descriptions of the input calculations and the calculational models used and the justification of their validity and adequacy. A transient of this type can result in achieving fuel melt temperatures and potential fuel damage.

(2) Safety Objective:

To assure that the consequences of this event do not exceed specified fuel design limits and that the protection system action be initiated automatically.

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*Reviewed for PWRs only; Standard Review Plan, Sections 15.4.1 and 15.4.2 cover BWRs and no additional areas considered.

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(3) Status:

Reviewed during reload, Technical Specifications revised to compensate for changes in analytical results.

(4) Reference:

Standard Review Plan, Section 15.4.3

TOPIC: XV-9 Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate

(1) Definition:

Review BWRs for (1) startup of an idle recirculation pump and (2) a flow controller malfunction causing increased recirculation flow. Review PWRs with loop isolation valves for startup of a pump in an initially isolated inactive reactor coolant loop where the rate of flow increase is limited by the rate at which isolation valves open. For PWRs without loop isolation valves, review startup of a pump in any inactive loop. If clad failures are calculated, determine that offsite consequences are acceptable.

(2) Safety Objective:

To verify that the plant responds in such a way that the criteria regarding fuel damage and system pressure are met (that is, no more than a small fraction of the fuel rods fail, that radiological consequences are a small fraction of 10 CFR Part 100 guidelines, and that the system pressure is limited in order to protect the reactor coolant pressure boundary from overpressurization.)

(3) Status:

PWRs reviewed against the final safety analysis report, BWR reviewed at each reload, Technical Specifications required to preclude exceeding safety limits during transients.

(4) Reference:

Standard Review Plan, Sections 15.4.4 and 15.4.5

TOPIC: XV-10 Chemical and Volume Control System Malfunction That Results in a Decrease in Boron Concentration in the Reactor Coolant (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of moderator dilution. An accident of this type could result in a departure from nucleate boiling and a loss of shutdown margin.

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(2) Safety Objective:

To confirm that the plant responds to the events in such a way that the criteria regarding fuel damage and system pressure are met and adequate time allowed for the operator to terminate the dilution before the shutdown margin is reduced. (Reactor coolant pressure and main steam pressure should be limited in order to protect the reactor coolant pressure boundary from overpressurization.) (Operator action must be initiated within 30 minutes following this event if refueling, and within 15 minutes during other modes of operation.)

(3) Status:

Only reviewed during initial operating-license review and not thereafter. The consequences may not have been calculated in accordance with current practice.

(4) Reference:

Standard Review Plan, Section 15.4.6

TOPIC: XV-11 Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (BWR)

(1) Definition:

Review the spectrum of misloading events analyzed to verify that the worst situation undetectable by incore instrumentation has been identified. This review will include an assessment of the plant's offgas and steam line radiation monitors to detect fuel damage and their capability to automatically isolate the offgas system when necessary.

(2) Safety Objective:

To assure that a misloaded assembly is detected and if undetected will not result in exceeding fuel safety limits or radioactive releases.

(3) Status:

Reviewed during reloads, Technical Specifications developed to limit consequences of worst misloaded assembly to small fraction of 10 CFR Part 100 guidelines. Technical Specifications setpoints for radiation monitors alarm/isolation signals have been found deficient and have been updated on a case-by-case basis for several plants.

(4) Reference:

Standard Review Plan, Section 15.4.7

TOPIC: XV-12 Spectrum of Rod Ejection Accidents (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences, including radiological consequences, of PWR control rod ejection accidents,

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and review the Technical Specifications regarding control of reactivity worth and technical specifications on primary to secondary leakage. Ejection of a control element assembly from the core can occur if the control element drive mechanism housing or the nozzle on the reactor vessel head breaks off circumferentially. The ejection of a control element assembly by the reactor coolant system pressure can cause a severe reactivity excursion. This accident may result in high doses for those plants where fuel failures are postulated to occur as a result of the accident. This accident usually determines the maximum allowable steam generator leak rate.

(2) Safety Objective:

To ensure that if a control element assembly ejection occurs, core damage is minimal, no additional reactor coolant pressure boundary failures occur, the calculated radial average energy density is limited to 280 cals/gm at any axial fuel location in any fuel rod, and that the radiological consequences will not exceed appropriate limits.

(3) Status:

Releases through the containment and/or steam generator leaks are analyzed for current plants, but were not reviewed routinely for older plants. Many of the operating plants have no leak Technical Specifications or they are excessively high. During each reload by the staff, the previously determined limiting transient is reviewed to determine if the new ejected rod worth is more restrictive than the reference analysis values.

(4) References:

1. Standard Review Plan, Section 15.4.8
2. Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors"

TOPIC: XV-13 Spectrum of Rod Drop Accidents (BWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of BWR control rod drop accidents and review the Technical Specifications regarding control of rod activity worth. An uncoupled rod may hang up in the core when the control rod drive is withdrawn and drop later when the consequences of a rapid control rod withdrawal are most severe. An analysis of the radiological consequences from this accident will be included.

(2) Safety Objective:

To limit the effects of a postulated control rod drop to the extent that reactor coolant pressure boundary stresses are not exceeded and core damage is minimal. To assure that the radial average fuel rod enthalpy at any axial location in any fuel rod is limited to less than 280 cals/gm following the worst reactivity excursion and to assure that the radiological consequences do not exceed appropriate guidelines.

(3) Status:

The potential for and reactivity consequences of an accidental control rod drop are now routinely evaluated prior to issuance of an operating license and any time thereafter when changes could affect the accident results or probability of occurrence. Radiological consequences may not have been calculated in accordance with present practice.

(4) Reference:

Standard Review Plan, Section 15.4.9

TOPIC: XV-14 Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory

(1) Definition:

Review the assumptions, calculational models used, and consequences of actuation of the high pressure coolant injection system or faulty operation of the volume control system. The chemical and volume control system regulates both the chemistry and the quantity of coolant in the reactor coolant system. Changing the boron concentration in the reactor coolant system is a part of normal plant operation, compensating for long-term reactivity effects. Actuation of these systems could increase the volume of coolant within the reactor coolant pressure boundary (RCPB) causing a high water level, possible high power level, and high or low pressure. If clad failure is calculated, determine that offsite consequences are acceptable.

(2) Safety Objective:

To assure that water added to the RCPB does not cause transients that exceed RCPB pressure limits or result in unacceptable fuel damage. No activity is released during the transient, but the transient may subsequently result in increased radioactivity in gaseous releases during normal operation.

(3) Status:

This transient is now routinely analyzed prior to issuance of an operating license and any time thereafter when proposed changes would affect the transient results. Radiological consequences may not have been calculated in accordance with current practice.

(4) Reference:

Standard Review Plan, Section 15.5.1

TOPIC: XV-15 Inadvertent Opening of a PWR Pressurizer Safety/Relief Valve or a BWR Safety/Relief Valve

(1) Definition:

Review the assumptions, calculational models used, and consequences of inadvertent opening of a PWR pressurizer safety/relief valve or a BWR

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safety/relief valve. Loss of reactor coolant inventory and depressurizing action of the reactor coolant system can occur if the PWR pressurizer safety/relief valve or the BWR safety/relief valves open spuriously, or open when required but fail to reclose properly.

(2) Safety Objective:

To preserve fuel cladding integrity during reactor coolant system depressurization transients resulting from faulty operation of a relief or safety valve while at rated power.

(3) Status:

The transient is now evaluated prior to issuance of an operating license and any time thereafter when proposed changes could affect the transient results.

(4) References:

1. Standard Review Plan, Section 15.5.1
2. Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants"

TOPIC: XV-16 Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment

(1) Definition:

Review the assumption, calculational models used, and radiological consequences of failure of small lines carrying primary coolant outside containment and review the Technical Specifications associated with primary coolant radioactivity concentrations, isolation valve closure times, and isolation valve leakage limits. In the event of a rupture of any component in the instrument lines outside primary containment, primary coolant and any radioactivity contained in the coolant or released to the coolant during the transient will be released if the instrument lines are connected to the reactor coolant pressure boundary. Primary coolant sample lines if broken outside primary containment can also allow coolant and radioactivity in the coolant to escape in the same manner. When these lines discharge to secondary containment, the integrity of the secondary containment and the efficiency of the filtration systems must be determined.

(2) Safety Objective:

To assure that any release of radioactivity to the environment is substantially below the guidelines of 10 CFR 100.

(3) Status:

The radiological consequences of small line breaks outside of primary containment have been evaluated routinely since 1970 prior to issuance of operating licenses, but have not always included the effects of iodine spikes during the depressurization transient.

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(4) References:

1. Regulatory Guide 1.11, "Instrument Lines Penetrating Primary Reactor Containment"
2. 10 CFR Part 50, Appendix A, GDC 55 and 56
3. Standard Review Plan, Section 15.6.2

TOPIC: XV-17 Radiological Consequences of Steam Generator Tube Failure (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of a steam generator tube failure with and without loss of offsite power and review the Technical Specifications associated with coolant activity concentrations. Steam generator tube failures allow escape of reactor coolant into the main steam system and to the environment. An analysis of the radiological consequences of this accident will be included.

(2) Safety Objective:

To assure that the plant responds in a proper manner to this accident, including appropriate operator actions, and to assure that radioactivity released following steam generator tube failure(s) is a small fraction of the 10 CFR 100 guidelines and within 10 CFR 100 for the case of a coincident iodine spike.

(3) Status:

The iodine release mechanism may not have been analyzed in accordance with present assumptions and methods for some of the older PWRs. Some operating plants do not have iodine activity limits in their Technical Specifications or have inappropriately high limits.

(4) References:

1. Standard Review Plan, Section 15.6.3
2. Regulatory Guide 1.5, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Steam Line Break Accident for Boiling Water Reactors"

TOPIC: XV-18 Radiological Consequences of Main Steam Line Failure Outside Containment

(1) Definition:

Review the assumptions, calculational models used, and consequences of failure of a main steam line outside containment and review the Technical Specifications associated with primary coolant activity concentrations and main steam isolation valve closure times.

(2) Safety Objective:

A steam line break outside containment allows radioactivity to escape to the environment. To limit the release of radioactivity to the environment

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to well within the guidelines of 10 CFR 100 in the event of a large steam line break, the primary coolant radioactivity must be appropriately limited by Technical Specifications.

(3) Status:

Some operating plants do not have appropriate coolant activity Technical Specifications.

(4) Reference:

Standard Review Plan, Section 15.6.4

TOPIC: XV-19 Loss-of-Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary

(1) Definition:

Review the licensee's analyses of the spectrum of loss-of-coolant accidents (LOCAs) including break locations, break sizes, and initial conditions assumed, the evaluation model used, failure modes, radiological consequences, acceptability of auxiliary systems, functional capability of the containment, and the effects of blowdown loads. LOCAs are postulated breaks in the reactor coolant pressure boundary resulting in a loss of reactor coolant at a rate in excess of the capability of the reactor coolant makeup system. LOCAs result in excessive fuel damage or melt unless coolant is replenished.

(2) Safety Objective:

To assure that the consequences of loss-of-coolant accidents are acceptable; that is, that the requirements of 10 CFR 50.46 and Appendix K to 10 CFR 50 are met, that the radiological consequences of a design basis loss-of-coolant accident from containment leakage and the radiological consequences of leakage from engineered safety features outside containment are acceptable, and the structural effects of blowdown are acceptable.

(3) Status:

Emergency core cooling system (ECCS) evaluation is a generic item which is currently under review or is complete for all operating reactors (La Crosse and San Onofre have stainless steel cores and have analyses completed to show conformance with the Interim Acceptance Criteria). Related generic items currently under review are reevaluations for increased vessel head fluid temperatures in W PWRs, effects of core flow on BWR LOCA analyses, GE ECCS input errors, and non-jet pump BWR core spray cooling coefficients. Radiological consequences are not routinely rereviewed.

(4) Reference:

Standard Review Plan, Section 15.6.5 and its Appendices

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TOPIC: XV-20 Radiological Consequences of Fuel-Damaging Accidents (Inside and Outside Containment)

(1) **Definition**:

Review the assumptions, calculational models used, and consequences of postulated fuel damaging accidents inside and outside containment and review Technical Specifications associated with fuel handling and ventilation system and filter systems, including interlocks on fuel movement and damage from fuel cask drop and tipping. Include in the review the assumed activity available for release, decontamination factors, filter efficiencies, activity transport mechanisms and rates, ventilation system potential release pathways, and calculated doses.

(2) **Safety Objective**:

To assure that offsite doses resulting from fuel damaging accidents, resulting from fuel handling, or dropping a heavy load on fuel are well within the guideline values of 10 CFR Part 100.

(3) **Status**:

The radiological consequences of fuel handling accidents inside containment are currently being performed as a generic review for PWRs. The radiological consequences of fuel damaging accidents outside containment of operating plants are only evaluated if Technical Specifications are reviewed.

(4) **References**:

1. Standard Review Plan, Section 15.7.4
2. Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors"

TOPIC: XV-21 Spent Fuel Cask Drop Accidents

(1) **Definition**:

Review the potential for spent fuel cask drops, the damage which could result from cask drops, and the radiological consequences of a cask drop from fuel damaged within the cask under conditions exceeding the design basis impact on the cask.

(2) **Safety Objective**:

To assure that the damage to fuel within the casks and radiological consequences resulting from a cask drop are acceptable or that acceptable measures have been taken to preclude cask drops.

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(3) Status:

Fuel cask drop analysis is a generic item which has been completed on some plants or is currently under review for all other operating reactors.

(4) References:

1. Standard Review Plan, Section 15.7.4
2. Regulatory Guide 1.25 "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors"
3. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book)

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-36, "Control of Heavy Loads Near Spent Fuel" (NUREG-0649)

The review criteria required by USI A-36 (Standard Review Plan, Section 15.7.5) are identical to the review criteria specified in the References of SEP Topic IX-2; therefore, this SEP topic has been deleted.

TOPIC: XV-22 Anticipated Transients Without Scram

(1) Definition:

Review the postulated sequences of events, analytical models, values of parameters used in the analytical models, and the predicted results and consequences of events in which an anticipated transient occurs and is not followed by an automatic reactor shutdown (scram). Analyses of the radiological consequences for these transients will be included. Failure of the reactor to shut down quickly during anticipated transients can lead to unacceptable reactor coolant system pressures and to fuel damage.

(2) Safety Objective:

To assure that the reliability of the reactor shutdown systems is high enough so that anticipated transient without scram (ATWS) events need not be considered or to assure that the consequences of ATWS events are acceptable; that is, that the reactor coolant system pressure, fuel pressure, fuel thermal and hydraulic performance, maximum containment pressure, and radiological consequences are within acceptable limits.

(3) Status:

ATWS is a generic topic currently under review to determine a position for all power reactors. BWR licensees have been requested to install reactor coolant pump trips as a short-term program measure. All licensees have submitted descriptions of the applicability of vendor generic ATWS reports for their plants. The schedule for review of Class C plants, which includes those plants designated for Phase II of SEP, has not yet been developed.

(4) References:

1. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book)
2. WASH 1270, "Technical Report on Anticipated Transients Without Scram for Water-Cooled Power Reactors," September 1973
3. Standard Review Plan, Section 15.8 and Appendix

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-9, "Anticipated Transients Without Scram" (NUREG-0606)

  The reference cited in this topic, that is, NUREG-0328, was the precursor of USI A-9. The evaluation required for USI A-9 is identical to SEP Topic XV-22; therefore, this SEP topic has been deleted.

TOPIC: XV-23 Multiple Tube Failures in Steam Generators

(1) Definition:

Assess the effects of multiple steam generator tube failures (ranging from leaks to double-ended ruptures) as a result of pressure differentials that may occur following a loss-of-coolant accident (LOCA), steam line break, or anticipated transient without scram (ATWS) events.

(2) Safety Objective:

Assure that the reflood of the core following a LOCA is possible and that the radiological consequences following these accidents are within the 10 CFR Part 100 guidelines.

(3) Status:

The consequences of multiple tube failures have not been analyzed for any plant at the licensing stage. Work has been done for some operating plants, but ultimate goals have yet to be set.

(4) References:

1. Prairie Island Nuclear Station, Docket Nos. 50-282 and 50-306
2. Turkey Point Plant, Docket Nos. 50-250 and 50-251
3. Surry Power Stations, Units 1 and 2, Docket Nos. 50-280 and 50-281

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-3, A-4, A-5, "Westinghouse, Combustion Engineering, Babcock and Wilcox Steam Generator Tube Integrity" (NUREG-0649)

Two of the tasks of USI A-3, A-4, A-5 are as follows:

1. Analyses of LOCA with Concurrent Steam Generator Tube Failures
2. Analyses of Main Steam Line Break

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The analyses required by these two tasks in USI A-3, A-4, A-5 cover two of the three events specified in the Definition.

(b) USI A-9, "Anticipated Transients Without Scram" (NUREG-0606)

Pressure differentials resulting from ATWS events have been determined to be no greater than those resulting from main steam line break events (NUREG-0460, Volume 2, Appendix V). The analysis for ATWS event is, therefore, covered under USI A-3, A-4, and A-5.

The evaluation required for USI A-3, A-4, A-5 is identical to SEP Topic XV-23; therefore, this SEP topic has been deleted.

TOPIC: XV-24 Loss of All AC Power

(1) Definition:

Review plant systems to determine that following loss of all ac power (onsite and offsite) the reactor is shut down and core cooling can be initiated. Loss of all ac power causes loss of most emergency equipment and instrumentation.

(2) Safety Objective:

To assure that with only dc power, equipment design, diversity, and operator action are sufficient to initiate core cooling within a short time period (typically 20 minutes).

(3) Status:

Not an explicit SRP topic. Availability of some ac power is assumed in all accident/transient analyses. Topic may be considered as an auxiliary fuel pump or reactor core isolation cooling pump diversity spinoff.

(4) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-44, "Station Blackout" (NUREG-0606)

The problem description of USI A-44 is identical to the Definition of SEP Topic XV-24, and the review of USI A-44 would be the same as Topic XV-24; therefore, this SEP topic has been deleted.

TOPIC: XVI Technical Specifications

(1) Definition:

The existing Technical Specifications, associated with SEP topics, will be compared with the Standard Technical Specifications for deviations. Where significant differences exist, they will be identified and considered for upgrading. The bases for the specifications will be examined including trip setpoints and accounting for nuclear uncertainty. Where significant voids occur in existing specifications, appropriate values will be identified and considered for upgrading.

(2) Safety Objective:

To assure that the safety limits and operational safety measures are sufficiently specified for the plant to minimize the probability of accidents that could result from equipment failure, misoperation, or human error.

(3) Status:

See Topic XIII-1, "Conduct of Operations" for Section VI status. The other sections of the Technical Specifications are reviewed only to the extent that reloads, license amendments, or generic problems require.

(4) References:

1. Standard Technical Specifications; Regulatory Guide 1.8, "Personnel Selection and Training," and Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)"
2. Standard Review Plan
3. Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Chapter 16
4. 10 CFR Part 50, Section 50.36

TOPIC: XVII Operational Quality Assurance Program

(1) Definition:

Review the Quality Assurance (QA) Program with respect to safe and reliable operation of the plant.

(2) Safety Objective:

Since 1973, significant new guidance for operational QA programs in the form of Regulatory Guides and WASH documents has been issued describing how to meet the criteria of 10 CFR Part 50, Appendix B. The objective of this guidance is to assure that operation, maintenance, modification, and test activities do not degrade the capability of safety-related items to perform their intended functions.

(3) Status:

Generic review for compliance with current standards is under way. As of May 1977, 50 of the 63 operating plants have QA programs which meet current criteria. The 13 remaining plants are currently under review, with an estimated completion date of July 1977.

(4) References:

1. 10 CFR Part 50, Appendix B
2. WASH-1283, Revision 1, "Guidance on Quality Assurance Requirements During Design and Procurement Phase of Nuclear Power Plants," May 24, 1974
3. WASH-1284, "Guidance on Quality Assurance Requirements During the Operations Phase of Nuclear Power Plants," October 26, 1973

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4. WASH-1309, "Guidance on Quality Assurance Requirements During the Construction Phase of Nuclear Power Plants," May 10, 1974
5. American National Standards Institute, ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," February 19, 1976

U.S. Nuclear Regulatory Commission reports cited under "Basis for Deletion" include:

NUREG-75/111	Guide and Checklist for Development and Evaluation of State and Local Government Radiological Emergency Response Plans in Support of Fixed Nuclear Facilities" (Reprint of WASH-1293), Oct. 1975.
NUREG-0153	"Staff Discussion of 12 Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum from Director, NRR, to NRR staff," 1976.
NUREG-0313	"Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," July 1977.
NUREG-0328	"Regulatory Licensing: Status Summary Report" (Pink Book).
NUREG-0371	"Approved Category A Task Action Plans," Nov. 1977.
NUREG-0410	"NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants, Report to Congress," Dec. 1977.
NUREG-0460	"Anticipated Transients Without Scram for Light Water Reactors," Vol. 2, Apr. 1978.
NUREG-0471	"Generic Task Problem Descriptions - Category B, C, and D Tasks," Sept. 1978.
NUREG-0484	"Methodology for Combining Dynamic Responses," May 1980.
NUREG-0510	"Identification of Unresolved Safety Issues Relating to Nuclear Power Plants--A Report to Congress 1979," Jan. 1979.
NUREG-0554	"Single-Failure-Proof Cranes for Nuclear Power Plants," May 1979.
NUREG-0577	"Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports," Sept. 1979.
NUREG-0606	"Unresolved Safety Issues Summary," issued quarterly.
NUREG-0609	"Asymmetric Blowdown Loads on PWR Primary Systems, Resolution of Generic Task Action Plan A-2," Jan. 1981.
NUREG-0649	"Task Action Plan for Unresolved Safety Issues Related to Nuclear Power Plants," Feb. 1980.

NUREG-0654	"Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Feb. 1980.
NUREG-0660, Rev. 1	"NRC Action Plan Developed as a Result of the TMI-2 Accident," Vols. 1 and 2, May 1980, Rev. 1, Aug. 1980.
NUREG-0691	"Investigation and Evaluation of Cracking Incidents in Piping in Pressurized Water Reactors," Sept. 1980.
NUREG-0705	"Identification of New Unresolved Safety Issues Relating to Nuclear Power Plants," Mar. 1981.
NUREG-0737	"Clarification of TMI Action Plan Requirements," Nov. 1980.
NUREG-0800	"Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," July 1981 (formerly NUREG-75/087).
NUREG/CR-1321	"Final Report - Phase I. Systems Interaction Methodology Applications Program," Apr. 1980.

APPENDIX B

SEP TOPICS DELETED BECAUSE THEY ARE COVERED BY A TMI TASK, UNRESOLVED SAFETY ISSUE (USI), OR OTHER SEP TOPIC[1,2]

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[1] See "Basis for Deletion" in Appendix A under applicable SEP topic.

[2] Letter from G. C. Lainas (NRC) to all SEP licensees, Subject: Deletion of Systematic Evaluation Program Topics Covered by Three Mile Island NRC Action Plan, Unresolved Safety Issues, or Other SEP Topics, May 1981.

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SEP Topic No.	SEP title	TMI, USI, or SEP No.	TMI, USI, or SEP title
II-2.B	Onsite Meteorological Measurements Program	TMI II.F.3 TMI III.A.1	Instrumentation for Monitoring Accident Conditions Improve Licensee Emergency Preparedness - Short Term
II-2.D	Availability of Meteorological Data in the Control Room	TMI II.F.3 TMI III.A.1 TMI I.D.1	Instrumentation for Monitoring Accident Conditions Improve Licensee Emergency Preparedness - Short Term Control Room Design Reviews
III-8.D	Core Supports and Fuel Integrity	USI A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant System
III-9	Support Integrity	USI A-12 USI A-7 USI A-24 USI A-46 SEP III-6 SEP V-1	Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports Mark I Containment Long-Term Program Environmental Qualification of Safety-Related Equipment Seismic Qualification of Equipment in Operating Plants Seismic Design Considerations Compliance With Codes and Standards (10 CFR Part 50, Section 50.55a)
III-11	Component Integrity	USI A-46 USI A-2 SEP III-6	Seismic Qualification of Equipment in Operating Plants Asymmetric Blowdown Loads on Reactor Primary Coolant System Seismic Design Considerations
III-12	Environmental Qualification of Safety-Related Equipment	USI A-24	Qualification of Safety-Related Equipment
V-3	Overpressurization Protection	USI A-26	Reactor Vessel Pressure Transient Protection
V-4	Piping and Safe-End Integrity	USI A-42	Pipe Cracks in Boiling Water Reactors
V-8	Steam Generator Integrity	USI A-3, A-4, A-5	Westinghouse, Combustion Engineering, and Babcock and Wilcox Steam Generator Tube Integrity
V-13	Waterhammer	USI A-1	Waterhammer
VI-2.A	Pressure-Suppression-Type BWR Containments	USI A-7	Mark I Containment Long-Term Program
VI-2.B	Subcompartment Analysis	USI A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant System
VI-5	Combustible Gas Control	TMI II.B.7 USI A-48	Analysis of Hydrogen Control Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment
VI-7.E	Emergency Core Cooling System Sump Design and Test for Recirculation Mode Effectiveness	USI A-43	Containment Emergency Sump Reliability
VI-8	Control Room Habitability	TMI III.D.3.4	Control Room Habitability Requirements
VII-4	Effects of Failure in Nonsafety-Related Systems on Selected Engineered Safety Features	USI A-47 USI A-17	Safety Implications of Control System Systems Interactions in Nuclear Power Plants
VII-5	Instruments for Monitoring Radiation and Process Variables During Accidents	TMI II.F.1 TMI II.F.2 TMI II.F.3	Additional Accident Monitoring Instrumentation Identification of and Recovery From Conditions Leading to Inadequate Core Cooling Instruments for Monitoring Accident Conditions
IX-2	Overhead Handling Systems (Cranes)	USI A-36	Control of Heavy Loads Near Spent Fuel Pool
X	Auxiliary Feedwater System	TMI II.E.1.1	Auxiliary Feedwater System Evaluation
XIIII	Conduct of Operations	TMI I.C.6 TMI III.A.1 TMI III.A.2	Procedures for Verification of Correct Performance of Operating Activities Improve Licensee Emergency Preparedness - Short Term Improving Licensee Emergency Preparedness - Long Term
XV-21	Spent Fuel Cask Drop Accident	USI A-36	Control of Heavy Loads Near Spent Fuel Pool
XV-22	Anticipated Transients Without Scram	USI A-9	Anticipated Transients Without Scram
XV-23	Multiple Tube Failures in Steam Generators	USI A-3, A-4, A-5 USI A-9	Westinghouse, Combustion Engineering, and Babcock and Wilcox Steam Generator Tube Integrity Anticipated Transients Without Scram
XV-24	Loss of All AC Power	USI A-44	Station Blackout

APPENDIX C

PLANT-SPECIFIC SEP TOPICS DELETED, REFERENCE LETTER, AND REASON FOR DELETION

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SEP Topic No.	SEP title	Date of letter	Reason for deletion of topic
II-4.E	Dam Integrity	11/16/79	Not applicable to site
III-3.B	Structural and Other Consequences (e.g., Flooding of Safety-Related Equipment in Basements) of Failure of Underdrain Systems	11/16/79	Not applicable to site because site does not have a system whose function is to lower the groundwater table
III-7.A	Inservice Inspection, Including Prestressed Concrete Containments With Either Grouted or Ungrouted Tendons	5/7/81	Not applicable to this facility's design
III-7.C	Delamination of Prestressed Concrete Containment Structures	11/16/79	Not applicable to this facility's design
III-8.B	Control Rod Drive Mechanism Integrity	10/1/80	Not applicable to pressurized water reactors (PWRs)
III-10.C	Surveillance Requirements on BWR Recirculation Pumps and Discharge Valves	11/16/79	Not applicable to PWRs
IV-3	BWR Jet Pump Operating Indications	5/7/81	Not applicable to PWRs
V-1	Compliance With Codes and Standards (10 CFR 50.55a)	11/27/81	Reviewed under inservice inspection/inservice test program
V-2	Applicability of Code Cases	11/16/79	Not applicable to PWRs
V-9	Reactor Core Isolation Cooling System (BWR)	11/16/79	Not applicable to PWRs
V-12.A	Water Purity of BWR Primary Coolant	11/16/79	Not applicable to PWRs
VI-2.C	Ice Condenser Containment	11/16/79	Not applicable to this unit's containment design
VI-7.A.2	Upper Plenum Injection	5/7/81	Not applicable to this facility's design
V-7.A.4	Core Spray Nozzle Effectiveness	5/7/81	Not applicable to PWRs
VI-7.C.3	Effect of PWR Loop Isolation Valve Closure During a Loss-of-Coolant Accident on Emergency Core Cooling System Performance	11/16/79	Not applicable to this facility's design
VI-7.F	Accumulator Isolation Valves Power and Control System Design	11/16/79	Not applicable to this facility's design
VI-9	Main Steam Line Isolation Seal System (BWR)	11/16/79	Not applicable to PWRs
VII-7	Acceptability of Swing Bus Design on BWR-4 Plants	11/16/79	Not applicable to PWRs
XI-1	Appendix I	12/4/81	Being resolved under generic activity A-02, "Appendix I," and B-35, "Confirmation of Appendix I Models." (See "Basis for Deletion" in Appendix A under Topic XI-1.)
XI-2	Radiological (Effluent and Process) Monitoring Systems	12/4/81	Being resolved under generic activity A-02, "Appendix I." (See "Basis for Deletion" in Appendix A under Topic XI-2.)
XV-11	Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (BWR)	10/1/80	Not applicable to PWRs
XV-13	Spectrum of Rod Drop Accidents (BWR)	11/16/79	Not applicable to PWRs
XV-18	Radiological Consequences of Main Steam Line Failure Outside Containment	10/1/80	Not applicable to PWRs
XVI	Technical Specifications	11/5/80	Will be addressed after completion of the integrated assessment

APPENDIX D

RISK BASED CATEGORIZATION OF SAN ONOFRE SEP ISSUES

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SUMMARY OF STAFF REVIEW
OF SAI REPORT
"RISK BASED CATEGORIZATION OF
SAN ONOFRE SEP ISSUES"

The staff has reviewed the risk assessment performed by Science Applications, Inc. (SAI) for the San Onofre Unit 1 SEP issues (SAI-83-131-WA, Rev. 1) and is in general agreement with the recommendations and conclusions presented in the report. However, we have some additional recommendations regarding SEP Topics V-11.A and VI-7.B.

In Topic V-11.A, there are two issues of concern. The first issue is that given reverse flow past the CVCS check valves, if the CVCS pumps are not running, the low pressure piping could be exposed to the high pressure reactor coolant and a LOCA outside containment might occur. In their evaluation of this issue, SAI rated the risk of a LOCA outside containment as low and made no recommendations for modifications. However, due to the potential for a containment bypass LOCA, the staff recommends that the licensee verify the pressure isolation capability of the charging pump discharge check valves at each refueling.

The second issue in Topic V-11.A, is the lack of pressure-related interlocks in the SIS. SAI rated the risk of a LOCA outside containment to be medium given a left open MOV and a failed check valve in the same injection line and SAI made a recommendation for system modifications. SAI's analysis failed to account for the design rating of the injection lines. These lines were designed for 1400 psia. It is the staff's opinion that if it can be demonstrated that this piping has a low probability of failure when subjected to full reactor system design pressure, that the risk would be acceptably low.

In Topic VI-7.B, the issue is the short amount of time available for manual switchover from the injection mode to recirculation mode given the present system design. In their analysis of the issue, SAI rated the risk of core melt due to a large LOCA and failure of the ECCS (inadequate switchover) as medium. SAI recommended a redundant RWST level indicator and an automatic switchover mechanism. The staff recognizes that only one charging pump is autostarted and thus, only one pump could be damaged if the switchover were not completed in a timely fashion. Because of this, the staff finds it sufficient to provide an automatic trip of the feedwater/safety injection pumps on low level instead of an automatic switchover mechanism. This will significantly increase the time available for operator action.

Further description of the system design and details of the SAI report follow.

SAI-83-131-WA
Revision 1

RISK BASED CATEGORIZATION OF SAN ONOFRE SEP ISSUES

Bahman Atefi
Daniel Gallagher

July 18, 1984

Prepared for:

U.S. Nuclear Regulatory Commission
Washington, D.C.

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EXECUTIVE SUMMARY

This is an Executive Summary of the report, "Risk-Based Categorization of San Onofre SEP Issues." The main report provides details of the analysis used to classify the San Onofre SEP issues with respect to their importances to risk. These classifications have been performed using probabilistic risk assessment (PRA) techniques.

The issues have been examined from the perspective of the impact their resolution would have on risk from the plant. The classifications are based on the criteria given in Table Ex-1. Following are discussions of each issue, their classifications based on these criteria, and the supportive results of our analysis which were judged by these criteria.

The methodology adopted in this study was to examine the impact of each issue on the systems they affect and assess the importance of the issue by qualitative and quantitative consideration of a simplified fault tree developed for the particular system under consideration and insights of other PRAs. For each issue, we estimated the impact its resolution would have on the San Onofre fault trees and thus the impact on the risk at San Onofre. The San Onofre fault trees referred to here are the simplified fault trees that were developed for each issue when it was determined that such a fault tree would be necessary for the resolution of the issue. The "dominance" of a fault tree indicates whether that fault tree would appear in the dominant accident sequence. Since no comprehensive Probabilistic Risk Assessment (PRA) analysis has been performed for the San Onofre, overall results of other PRAs performed in the IREP, RSSMAP and Reactor Safety Study on the plants which are similar to San Onofre were used for judgments related to the effect of a system on dominant accident sequences.

Table Ex-2 gives the results of the classification of the issues as high, medium, or low importance to risk. The numbers denote the issues.

The rest of this executive summary consists of brief summaries of each of the issues evaluated and its risk resolution. The main report contains more detailed discussions of the methodology and the analysis of each issue.

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TABLE EX-1

Classification of Issues

Classification	Criterion
High	Resolution of issue dominates value of the top event of a dominant fault tree or dominant sequence event.
Medium	Resolution of issue impacts but does not dominate value of top event of dominant fault tree or dominant sequence event.
Low	Resolution of issues has no impact on value of top event of dominant fault tree or dominant sequence event.

TABLE EX-2

Classification of Issues
Importance to Risk

High	
IX - 5	Ventilation Systems
Medium	
V - 11.A	Requirements for Isolation of High and Low Pressure Systems
VI - 7.B	ESF Switchover from Injection to Recirculation Mode (Automatic ECCS Realignment)
VI - 7.C.2	Failure Mode Analysis ECCS
VIII - 3.B	DC Bus Voltage Monitoring
Low	
III - 8.A	Loose Parts Monitoring
III - 10.A	Thermal Overload Protection for Motors of Motor Operated Valves
IV - 2	Reactivity Control System Including Functional Design and Protection Against Single Failure
V - 10.A	Residual Heat Removal System Heat Exchanger Tube Failure
V - 11.B	RHR Interlock Requirements
VI - 4	Containment Isolation System
VI - 10.A	Response Time Testing
VII - 1.A	RPS Isolation
VII - 3	Systems Required for Safe Shutdown
VIII - 4	Electrical Penetrations of Reactor Containment
IX - 3	Station Service and Cooling Water Systems
XV - 2	Spectrum of Steam System Piping Failure Inside and Outside of Containment
Resolved	(These issues were analyzed for the draft, but completely resolved by the time the final report was completed.)
VII - 2	Engineered Safety Features (ESF) System Control Logic and Design
XV - 7	Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

III-8.A Loose Parts Monitoring and Core Barrel Vibration Monitoring

The San Onofre Nuclear Power Station does not have a loose parts monitoring system (for loose parts within the reactor coolant pressure boundary) to meet the requirements of Regulatory Guide 1.133. Features lacking for the system would include sensors on the exterior surface of the RCPB capable of detecting acoustic disturbances, system sensitivity specifications, alert levels, data acquisition modes and other system and procedural requirements.

The loose parts that would be detected by a loose parts monitoring system, lacking at San Onofre, have not been a significant cause of transients at nuclear power plants. Due to the relatively high transient frequency from other causes the elimination of loose parts induced transients has a small effect on the core melt frequency. This issue is of low risk significance.

III-10.A Thermal Overload Protection for Motors of Motor Operated Valves

Current criteria requires that the thermal overload protection for motors of MOVs be bypassed during emergency operation. Additionally, the trip set points of the thermal overload protection for the motor operated valves should be established such that with all the uncertainties included, the valve be capable of completing its safety related function.

In the analysis of this issue no evaluation of the adequacy of the current set points for the thermal overload protection of MOV's was performed. To determine the effect of bypassing of the thermal overload protection for MOVs during emergency operation, the contribution of thermal overload failure on the total failure of the MOV on demand was calculated. It was shown that bypassing of the thermal overload protection results in a 14% reduction in the failure probability of MOVs on demand. The only system with an unbypassed MOV is the Component Cooling Water System (CCWS). The effect of reduction in failure demand probability of the MOVs on this system was evaluated. It was found that the overall effect of this reduction in MOV failure rate on the failure probabilities of the CCWS system is

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negligible. Thus, it is concluded that bypassing of the MOV's thermal overload protection device has a very small effect on the overall core melt frequency. Consequently, the risk significance of this issue is rated low.

IV-2. Reactivity Control System Including Functional Design and Protection Against Single Failure

General Design Criteria (GDC) 25 requires that no single failure of the reactor control and protection system, such as rod withdrawal, would result in reactivity and power increases that could exceed fuel design limits. In San Onofre it was found that single failures in the reactor trip system could lead to malfunctions such as multiple rod withdrawals that could exceed fuel design limits. Rod withdrawal accidents are contributors to the frequency of initiation of transients in light water reactors. As long as the mitigating systems designed to mitigate the consequences of these transients function correctly, no core melt accident would result. The most important consequence of a rod withdrawal accident is localized power peaking in the fuel bundles in the vicinity of the withdrawn control rod. This localized power peaking could result in some cladding damage but no fuel damage or melting is expected. In the previous comprehensive probabilistic risk assessments such as WASH-1400 it has been shown that the most significant contribution to the overall risk of operation of a Nuclear Power Plant comes from the accidents that involve core meltdown. Consequently the rod withdrawal accidents that do not lead to core meltdown are not expected to contribute significantly to the risk of operation of this plant and are ranked low from risk significance point of view.

V-10.A Residual Heat Removal System Heat Exchanger Tube Failures

San Onofre currently does not meet the criteria for monitoring of the possible leakage of primary coolant through component cooling and salt water cooling systems to the environment.

The possibility of in leakage from component cooling water system to the primary water system is extremely low. This event can only occur during shutdown periods where the primary side of the residual heat removal heat exchangers are at a pressure that ranges from 70 psig to 420 psig and the

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secondary side, which is the component cooling water, is at a pressure of 65-75 psig. The salt water cooling system which removes heat from component cooling water system and is the source of possible impurities is at 30 psig and is always at a lower pressure than component cooling water system.

The frequency of primary coolant leakage to the environment was conservatively calculated by looking at failure probabilities of component and salt water cooling systems heat exchanger failures. The frequency of this event was calculated to be 6.8×10^{-8}/year. Considering the low frequency of this event and low significance of its consequences compared to a core melt accident, the overall effect of this issue on the risk due to operation of the San Onofre plant is judged to be very small. Thus, this issue is ranked low with respect to risk.

V-11.A Requirements For Isolation of High and Low Pressure Systems

There are three systems at San Onofre that are connected to the main coolant system and have lower pressure than the main coolant system. These systems are the residual heat removal system (RHRS), safety injection systems (SIS) and the chemical and volume control system (CVCS). The current design of these systems does not meet the NRC criteria that requires existence of a pressure interlock mechanism such that the possibility of exposure of the low pressure segments of the above systems to the main coolant and subsequent initiation of a LOCA can be avoided. The RHRS system requirements are discussed under topic V-11.B "RHR Interlock Requirements." The safety injection system including the long term recirculation system and chemical and volume control system were analyzed to find the probability of a leakage from RCS to the low pressure segments of the above systems. The results showed that the probability of the main coolant leakage to the CVCS and long term recirculation system due to failure of various check valves resulting in a possible LOCA is 9.4×10^{-7} and 7.0×10^{-7} per year respectively. The probability of initiation of a LOCA outside containment as a result of reverse leakage in the SIS is 1.7×10^{-5}. The scenario leading to this LOCA consists of failure to close the safety injection system MOV's following a refueling outage test and failure of a check valve while reactor is at power. To reduce this frequency, two possible improvements to the system can be suggested. The first one consists of addition of a pressure interlock to the safety injection system MOV's. This reduces the frequency of a

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LOCA to 2.8×10^{-8}/year. An alternative to this is to assure that the MOV's are closed before the reactor is taken back to power by adding a second crew that would check the status of the MOV's at the end of the refueling outage. This will reduce the frequency of the LOCA to 1.7×10^{-6}/year. The frequency of initiation of a LOCA due to reverse leakage in the CVCS and long term recirculation system are sufficiently low that they are not expected to contribute significantly to the overal frequency of initiation of a LOCA. Thus, these are ranked low with respect to risk. In the case of the SIS this frequency is sufficiently high that we would rank its risk significance as medium.

V-11.B RHR Interlock Requirements

The isolation of the primary coolant system and the residual heat removal system (RHRS) at San Onofre is currently provided by two MOVs at the suction and two at the discharge line. Since the RHRS system is a low pressure system the concern is that in case of an inadvertent opening of these MOVs during plant cooldown at pressures above RHRS design pressure, the low pressure piping and components of the RHRS would be exposed to high pressure primary coolant and a LOCA could be initiated. Of the four MOVs isolating the primary coolant system and RHRS, two MOVs, one on the discharge and one on the suction, are connected to a pressure sensor so that if the primary coolant pressure is above RHRS design pressure they would not open. The other two MOVs are administratively controlled by the shift supervisor. Thus, for the RHRS to be exposed to a high pressure, two failures must occur. First, a human error on the part of the shift supervisor must occur such that the MOVs would be opened when the primary coolant pressure is above the RHRs design pressure AND the pressure sensor must fail to prevent the opening of one of the MOVs upon detecting a high pressure. The probability of a core melt due to this scenario was calculated to be 1.2×10^{-7}/yr. If the administratively controlled MOVs are replaced by MOVs with pressure sensors this core melt frequency reduces to 5.7×10^{-8}/yr. Although no PRA for San Onofre has been done, based on PRAs for similar PWRs in the IREP, RSSMAP and WASH-1400, the frequency of core melt is estimated to be in the range of 3×10^{-5} to 2×10^{-4}/yr. Thus, the above core melt frequencies have a very small effect on the overall core melt frequency and addition of another pressure sensor to the present interlock system does not

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seem to be necessary. Consequently the risk significance of this issue is ranked low.

VI-4 Containment Isolation System

Many of the containment penetrations in the San Onofre plant do not meet the NRC's current General Design Criteria. These penetrations fall into several categories.

The probability of failure of these penetrations in the current configuration and with the recommended modifications was evaluated. It was found that although a very small reduction in the failure probability of these penetrations can be realized by changing to the recommended configuration, the absolute failure probabilities of these penetrations are so small that the contribution of these failures to the total containment penetration would be insignificant. Thus, changing from the present isolation configuration to the recommended configuration does not seem to be necessary. Because of the very small effect of the present isolation system configuration on the total probability of isolation failure, this issue is ranked low as far as the risk is concerned.

VI-7.B ESF Switchover from Injection to Recirculation Mode (Automatic ECCS Realignment)

The switchover from Emergency Core Cooling injection to recirculation in the San Onofre plant is currently performed manually. The operator is instructed by an alarm to reduce the injection flow once the Refueling Water Storage Tank (RWST) level has dropped to 21%. The switchover tasks must be initiated by the operator once the RWST level has dropped to 12% and should be completed before the level drops below 7% to avoid any possible damage to the pumps. The time available to the operator to complete the switchover tasks is between 5.8 to 10 minutes depending on the assumed rate of flow. Current NRC criteria recommends a minimum of 20 minutes for the manual switchover operation. In addition, currently there is only one level indicator from RWST to the control room that would be used by the operator to initiate the recirculation.

To analyze this issue a fault tree for the failure of the recirculation system was developed and quantified. The results showed that the failure probability of the current San Onofre recirculation mechanism is 2.5×10^{-2}. Based on a large LOCA frequency of 1.0×10^{-4} per year this lead to a core melt frequency of 2.5×10^{-6}/year.

Two alternatives to this configuration were analyzed. In the first case, addition of a set of redundant annunciated level instruments to the RWST was considered. This change resulted in reduction of the failure probability of the recirculation system to 3.7×10^{-3} which is a factor of 7 smaller than the present configuration. This leads to a core melt frequency of 3.7×10^{-7}/year.

The second case analyzed was the addition of an automatic switchover mechanism. This addition resulted in a further reduction in the failure probability of the recirculation system to 6.0×10^{-4} which is a factor of 6 smaller than the case with redundant level indicators but manual switchover. The core melt frequency in this case is 6.0×10^{-8}/year. It should be noted that an automatic switchover mechanism has a basic drawback in that initiation of an inadvertent switchover before there is sufficient water in the sump could result in possible pump cavitation and damage. Since the exact core melt frequency for the San Onofre is not known, the importance of the above scenarios are evaluated by comparing the above core melt probabilities with the typical core melt probabilities developed for similar PWRs in the IREP, RSSMAP and Reactor Safety Study. Based on these evaluations, the overall core melt frequency is in the range of 3×10^{-5} to 2×10^{-4}/year. Thus, it seems that the core melt frequency due to the present configuration of the recirculation system at San Onofre would have a moderate contribution to the total core melt probability. The order of magnitude reduction in this core melt frequency as a result of introduction of a set of redundant annunciated RWST level indicators would make this contribution essentially insignificant. This implies that the further reduction in this frequency based on the addition of an automatic switchover mechanism does not offer much benefit from the risk point of view. Based on the core melt frequency of the current design of the San Onofre, this issue is ranked as medium with respect to risk.

VI-7.C.2 Failure Mode Analysis ECCS

There are four items identified in this issue that could disable part of the Emergency Core Cooling System (ECCS) due to single failures. The licensee has agreed to the NRC recommendations on two items and has suggested modifications to the systems addressed by the other two items. These items which are analyzed in this issue are:

a. installation of redundant valve in series with valve MOV/LCV 1100C from volume control tank (VCT) to the charging pumps. Failure of MOV/LCV 1100C to close may cause cavitation of the two charging pumps downstream of the valve because hydrogen from the volume control tank could enter the pump suction.

b. Installation of redundant control power and instrument air for flow control valves FCV-1115D, E and F at the injection lines of the charging pumps. Loss of air pressure or power causes these valves to close with possibility of loss of ECCS recirculation to the three cold leg injection lines.

For the first item above four cases were analyzed. These include 1) the original configuration, 2) the licensee proposed configuration (i.e., the existing configuration) consisting of removing one of the charging pumps from the sequencer that would start it upon a safety injection system and manual transfer of power from redundant motor control centers (MCC) that provide power to the MOV/LCV 1100C, 3) the NRC recommended configuration where a second MOV is added to the system in series with the MOV/LCV 1100C, and the last case is the same as the licensee proposed case except that a second MOV is also added in series with MOV/LCV 1100C. The analysis showed that the current design could result in a core melt frequency of $1.0x10^{-6}$/year. The proposed licensee changes and NRC recommended configurations both reduce the above core melt frequency by three orders of magnitude to $1.0x10^{-9}$/year. The last case will result in another three orders of magnitude reduction in core melt probability. It is concluded that either the licensee proposed modification (Case 2) or NRC recommended changes (Case 3) is sufficient to reduce the core melt frequency.

For the second item the proposed interim configuration of air supply system with a new emergency air supply was analyzed. The modified configuration has a failure probability of 8.8×10^{-4}. Based on a small LOCA of 1.0×10^{-3}/year, this results in a core melt frequency of 8.8×10^{-7}/year. It was noted that the failure probability of either air supply system, i.e., the old system with no redundancy and the new system is dominated by the assumption of annual testing of various components of the system which would have been the case for the old non-redundant system. If after modification of the system and existence of redundancy the components are tested more frequently, the failure probability of the system would be reduced even further. Overall, without any proposed modifications, the risk significance of this issue would be ranked medium. With the above modifications in place the risk significance of this issue reduces to low.

VI-10.A Testing of Reactor Trip Systems and Engineered Safety Features, Including Response Time Testing

Two issues were identified: 1) response time testing is not performed and 2) no provision for channel checks of the steam flow channels is included in the technical specifications. In PRA analysis, the timing of system action is relatively unimportant because the time periods measured by response time testing are very short when compared to the actual amount of time the system can begin to function to prevent core melt. Functional testing, which is performed at San Onofre, is sufficient to test system operation within a reasonable time. Thus, the importance of response time testing to risk is low. Channel checks, on the other hand, do not have a significant effect on the reliability analysis of the reactor trip system. Thus, the importance of channel checks to risk is low.

VII-1.A Isolation of Reactor Protection System from Non-Safety Systems

Current criteria require that non-safety systems receiving output from the RPS have isolation devices to insure the independence of the RPS channels. At the San Onofre 1 plant proper isolation devices are lacking between remote meters and process recorders and the following RPS trip signals:

pressurizer pressure
presurizer level
steam-to-feedwater flow mismatch
high flux level
high startup rate neutron monitoring
reactor coolant flow.[1]

Additionally, there is no isolation between the steam-to-feedwater flow mismatch channel and the Optimac computer or between the nuclear instrumentation and a data logger. (Utility personnel state the data logger is no longer connected to the nuclear instrumentation.) A simplified fault tree was constructed to represent these trip signals including the effects of unisolated non-safety system faults. The analysis of this fault tree showed that the non-safety system faults did not contribute significantly to the RPS failure probability (dominated by the common mode mechanical failure of the rods to insert). We therefore rate this issue to be of low risk significance.

VII-2 Engineered Safety Features (ESF) System Control Logic and Design

Safety grade systems are required by current criteria to be adequately isolated from non-safety systems. ESF current loops are required to have isolation devices to ensure electrical independence of the ESF channels. At San Onofre 1 proper isolation devices may not be utilized for the containment isolation signal and the safety injection signal. The isolation device used for the safety injection signal is an input buffer module. The containment isolation signal is isolated through the use of relays and relay contacts. Assuming that the input buffer modules do not supply adequate isolation for the safety injection signal, the effects of faults in non-safety systems on the safety injection signal were analyzed. The probability of a signal failure due to unisolated faults was calculated to be of the same magnitude as safety injection system faults in other nuclear power

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[1] Not included in SEP branch evaluation; however, utility claims this signal's lack of isolation is identical to pressurizer pressure and level signals

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plants. This implies that faults in non-safety systems could be a significant contributor to safety injection signal failure at San Onofre 1. Adequate isolators between the safety injection signal and the non-safety systems would effectively eliminate the non-safety effects. After completion of the analysis of this issue, the licensee demonstrated that sufficient isolation exists between the safety and non-safety grade systems. Thus, this issue is completely resolved.

VII-3 Systems Required For Safe Shutdown

The only issue under this topic is the lack of redundancy in the Component Cooling Water System (CCWS) surge tank level indicator. Currently the water level in the surge tank is monitored by one level indicator which is connected to an alarm in the control room and would warn the operator of the low water level in the surge tank. In addition there is a visual gauge that is checked once every refueling. If low water level in the surge tank is detected operator can add makeup water to the tank manually. The concern in this issue is that given a leakage and failure to detect the low water level in the surge tank, the CCWS can cavitate and fail the operation of the system. This failure among other things could result in the failure of the main coolant pump seal creating a small-small LOCA. The probability of occurrence of this event was calculated to be 1.1×10^{-4}/year. This is an order of magnitude smaller than the overall probability of occurrence of a small-small LOCA of 1.0×10^{-3}/year. Considering all the conservatism involved in the analysis of this scenario and small contribution of this event to the initiation of a small-small LOCA which itself partially contributes to the total core melt probability of this plant, the significance of this issue is ranked low from risk point of view.

VIII-3.B DC Power System Bus Voltage Monitoring and Annunciation

There are two DC power systems at San Onofre 1, the 125V DC system and the uninterruptable power supply (UPS). Each of these systems should have sufficient control room indication to allow for operator action to 1) prevent the loss of a DC bus or 2) recover a DC bus if power is lost at the bus. The San Onofre 1 plant does not have all of the required annunciators and monitors for either DC power system.

Fault trees were constructed to model the two DC power systems. These fault trees were evaluated for the systems as they are now and for the systems assuming the proper annunciators are added. (Proper annunciation reduces the detection interval for most battery system faults.) The analysis showed that for both battery systems a reduction in the battery system unavailability is achievable with the improved annunciation. However since the UPS supplies power to only one component (a safety injection valve) whose failure probability is dominated by mechanical valve failures, the reduction in the UPS unavailability does not significantly affect the safety injection system unavailability. This is the only system the UPS could affect; therefore the reduction in UPS unavailability is not significant. Due to multiple power supplies to each of the 125V DC system batteries, both diesel generators can be used for each battery system, the failure probability of the unannunciated battery system is smaller at San Onofre 1 than at most nuclear power plants. The reduction in the battery system unavailability, due to improved annunciation, will not have as significant an effect as it would at other nuclear power plants. However, it should still have an effect on the risk due to core melt. We therefore rank this issue to be of medium risk significance.

VIII-4 Electrical Penetrations of Reactor Containment

This issue addresses the adequacy of the electrical penetrations in maintaining containment integrity during a LOCA given an overloaded circuit. For the low voltage penetrations analyzed no secondary circuit protection was provided (as required by present criteria). In this analysis the failure probability of containment isolation was calculated by considering failure probability of DC and low voltage AC penetrations. Failure probability of each of the above penetrations due to an overload was next multiplied by the total number of penetrations to get the total probability of containment isolation failure due to this event. The results show that failure probability of containment isolation due to failure of low voltage electrical penetrations is several orders of magnitude smaller than other contributors to the failure of the containment isolation. Thus, this issue is ranked low from risk point of view.

IX-3 Station Service and Cooling Water Systems

Several issues related to the Component Cooling Water System (CCWS) and Salt Water Cooling System (SWCS) were identified by the NRC for this topic. Among these, one issue for the CCWS and one for SWCS were relevant for analysis using PRA techniques. For the CCWS the importance of passive failures consisting of pipe rupture and heat exchanger failures was analyzed. To do this a simple fault tree for the CCWS was developed and quantified. With all the conservatism included in the assumptions for the passive failures the contribution of these failures to the failure of the CCWS is about 6%. Thus, the contribution of the passive failures to the overall core melt frequency was judged to be insignificant.

The issue related to the SWCS is the significance of failure of tsunami stop gates after reactor shutdown when the heat load is at its maximum and lack of sufficient time for the operator to correct the situation. In particular, it was found that during the maximum heat load conditions on SWCS, if one of the tsunami stop gates fails the water inventory in the screenwell will eventually be depleted. If the salt water flow is completely lost, there is only about 3 minutes before the water temperature in the CCWS increases above the design temperature. To evaluate the importance of failure of the tsunami stop gates, the unavailability of the SWCS following reactor shutdown was evaluated. This unavailability consists of the frequency of reactor scram time the unavailability of the tsunami gate valves during the approximately 24 hours of maximum heat load following a reactor scram. The probability of this event was calculated to be 6.4×10^{-6}/year. This frequency is considered lower than unavailability of SWCS due to hardware failure. Additionally, if SWCS is failed for an extended period of time, RHRS can be shutdown to reduce the heat load on SWCS. In this case the main coolant will heat up somewhat and the heat can be removed using the main heat exchangers. Considering these facts, the contribution of this event to the risk associated with the operation of this plant is judged to be low.

IX-5 Ventilation Systems

This topic addresses the need to provide further analysis to determine the need for ventilation to assure system operability. This in itself does not serve to reduce risk; however, a finding that ventilation is not needed in certain areas could serve to "reduce" the perceived potential for risk significance. The analysis performed was conservative and serves to indicate the upper bound for potential risk, thus indicating for which areas further analysis should be carried out. The conclusions for each plant area analyzed follow.

A loss of ventilation in the switchgear and cable spreading room would affect both trains of the AC power system, both normal and emergency. A ventilation failure induced loss of the equipment in this room combined with a failure of the turbine driven auxiliary feedwater pump portion of the auxiliary feedwater system would eliminate the standard means of removing heat from the core. The frequency of this combination of events is relatively high, comparable to the core melt frequency for a PWR. For this reason we rate this issue to be of high risk significance.

A loss of ventilation in the 480V switchgear room will affect only one train of the AC power system. The consequences of losing one AC power train are significantly less than those when both AC trains are lost. The availability of a redundant AC power supply and the auxiliary feedwater system, virtually unaffected by a loss of ventilation in the 480V switchgear room, reduce the significance of this event to a point where it would not significantly affect the core melt frequency. We rank this issue to be of low risk significance.

The reactor auxiliary building ventilation system provides ventilation for the charging pumps. The probability of a ventilation system failure that fails the charging pumps, in combination with other system failures required to result in a core melt sequence, is small in comparison with the expected core melt frequency. This issue is therefore rated to be of low risk significance.

The failure of one of the station batteries due to a loss of ventilation could have a significant effect on the San Onofre 1 core melt frequency. Failure of the ventilation system, a single fan, can be expected to occur more frequently than the loss of a DC power train due to battery faults. Battery faults generally are significant contributors to dominant accident sequences. This issue is therefore rated to be of high risk significance.

XV-2 Spectrum of Steam System Piping

The concern in this issue is to show that the plant has the ability to mitigate consequences of steam line breaks. Overall, it was shown that the pressure in the reactor coolant and main steam systems will stay below the design pressure following a steam line break. The simultaneous blowdown of all three steam generators can cause a pressurized thermal shock to the reactor pressure vessel. This issue is being considered as a part of the generic unresolved safety issues. Loss of a single motor-driven-auxiliary feedwater pump could disable the decay heat removal via steam generators if a main feedwater pump is not realigned to perform the auxiliary feedwater pump function. The Licensee has proposed to add a second motor driven auxiliary feedwater pump that would eliminate the above concern. Consequently the significance of this issue is ranked low from risk point of view.

XV-7 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

Given a loss of forced flow due to reactor coolant pump rotor seizure or shaft break, NRC evaluation shows that there is no effect on the minimum DNBR. But it could not be concluded whether the reactor coolant pressure would exceed the allowable limits. Looking at the various causes for reactor coolant pump failure, experience has shown that only about 2% of the pump failures are due to the above causes. Given the small probability of overpressurization of main coolant system based on this event and small consequences of the event compared to core melt accidents, the importance of this issue is ranked low from risk point of view. Although analyzed, this issue was completely resolved before completion of the final report.

I. Introduction

This report will present the analysis and results for the risk-based categorization of issues identified by the USNRC Systematic Evaluation Program (SEP) for the San Onofre Nuclear Power Plant.

Section II will discuss the methodology, Section III will present our results for San Onofre, and Section IV will give the analysis performed for each San Onofre SEP issue.

A brief discussion of the analysis and results for each issue is given in the Executive Summary of this report.

II. Methodology for Categorization of San Onofre SEP Issues

The United States Nuclear Regulatory Commission (USNRC) Systematic Evaluation Program (SEP) is identifying deviations from current licensing requirements for older nuclear power plants. This project evaluates those issues which are amendable to study by probabilistic risk assessment (PRA) techniques, for the San Onofre plant. The result of this evaluation is the categorization of these issues by the impact their resolution would have on risk. This categorization will be used as input to the USNRC decisions on what hardware and procedure changes will be required for the nuclear plants as the product of the SEP.

Not all of the issues identified are easily addressed by well-defined PRA techniques. In particular, issues which address the ability of the power plant to safely deal with events for which the frequency and/or effects on plant systems are unknown are not evaluated in this study. PRA examines accident scenarios for which the initiating event frequencies are relatively well known and probabilities of system failures are estimated by detailed consideration of system configuration, random component failures, and system interactions. Thus the issues evaluated are those which address systems or plant features during normal operation or accident situations of relatively well-known frequency where that system or plant feature may be demanded.

Issues excluded are those dealing with seismic, tornado, or flooding events for which the frequency of a given severity event, or any such event, is not well known. Also excluded are issues dealing with high energy line breaks, where it is not the frequency, but the effects on systems, which is not known. Treating these issues in the framework of PRA would generally be at the edge of the state-of-the-art (since event frequencies, etc., are not well known) and thus our confidence in the risk-based categorization of these issues would be less than for the results of our analysis of those issues which fit well into present PRA considerations.

Since no probabilistic risk assessment has been performed for the San Onofre Nuclear Power Plant, the results of other PRAs performed in the IREP, RSSMAP and reactor safety study on similar PWRs were used for judgments on the importance of an issue to the risk.

The method adopted in this study was to examine the impact of each issue on the systems it affects and assess the importance of the issue by both quantitative and qualitative consideration of the fault trees and the results and insights of other PRAs.

For each issue, we consider the impact its resolution would have on the unavailability of the system under consideration by developing a simple fault tree for the system or subsystem of interest. If the impact of the proposed changes on unavailability of the system under consideration is significant, the next step is to evaluate the impact of the issue on the core melt sequences that includes failure of the system under consideration.

If we could ascertain no impact on the top event of any dominant fault tree (or event in any dominant sequence) due to resolution of an issue, we classified the issue's importance as low. If the resolution of the issue affects but does not dominate a fault tree (or event), the issue was classified as of medium importance. If the resolution of the issue dominates the value of the top event of any dominant fault tree (or event), the issue's importance was classified as high.

In general, the evaluation was done in consecutive phases in order to reduce the amount of work as much as possible while still getting the required insights to assure a proper ranking.

> Phase I - Evaluate the effect of the SEP issue resolution on the particular event or component it is associated with. That is, determine if there is a frequency/reliability change induced on the event/component by resolving the issue as suggested by the NRC. If there is essentially no effect, no further analysis is required and the risk significance is low. If there is an effect, proceed to Phase II.
>
> Phase II - Evaluate the effect of the frequency/reliability change found in Phase I on the overall reliability of the systems which it impacts. If there is essentially no effect, no further analysis is required and the risk significance is low. If there is an effect, proceed to Phase III.

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Phase III - Evaluate the effect of the reliability change found in Phase II on perceived plant risk/core melt frequency. If there is essentially no effect, the risk significance is low. If there is an effect but it does not involve the perceived dominant contributors to risk, the risk significance is moderate. If there is an effect and it involves a perceived dominant contributor to risk, the risk significance is high.

From this description, it can be seen that some subjective judgment is required for Phase III as to what are the perceived dominant contributors to risk and what is the perceived total plant risk/core melt frequency. To some extent, this is based on the experience gained from other PRAs done on similar plants. In general, when an issue was judged using other PRAs the ranking of the issue was based on the PRA which showed the greatest effect. Thus, if an issue was shown to be dominant (high) for any one of the PWR PRAs considered, it was concluded that it might also prove to be dominant for San Onofre, and it was ranked high. On the other hand, in order to be ranked low, the issue would have to be shown to be low for all of the PWR PRAs considered. It is obvious that this will result in a more conservative analysis.

The overall study methodology is given in flowchart form in Figure 1. The importance of an issue is determined by the impact of resolution of the issue on the San Onofre fault trees or events and the dominance or nondominance of accidents containing those faults or events. The impacts are developed from the SEP branch evaluations of the issues and the fault trees developed for each issue. The "dominance" of the San Onofre fault trees and events is determined as previously stated from the results of other PRAs performed in the IREP, RSSMAP and reactor safety study on similar PWRs. The resulting classifications are given in Table 1.

A discussion of each issue and its classification is given in the Executive Summary of this report. The next section provides a brief overview of the results of this study.

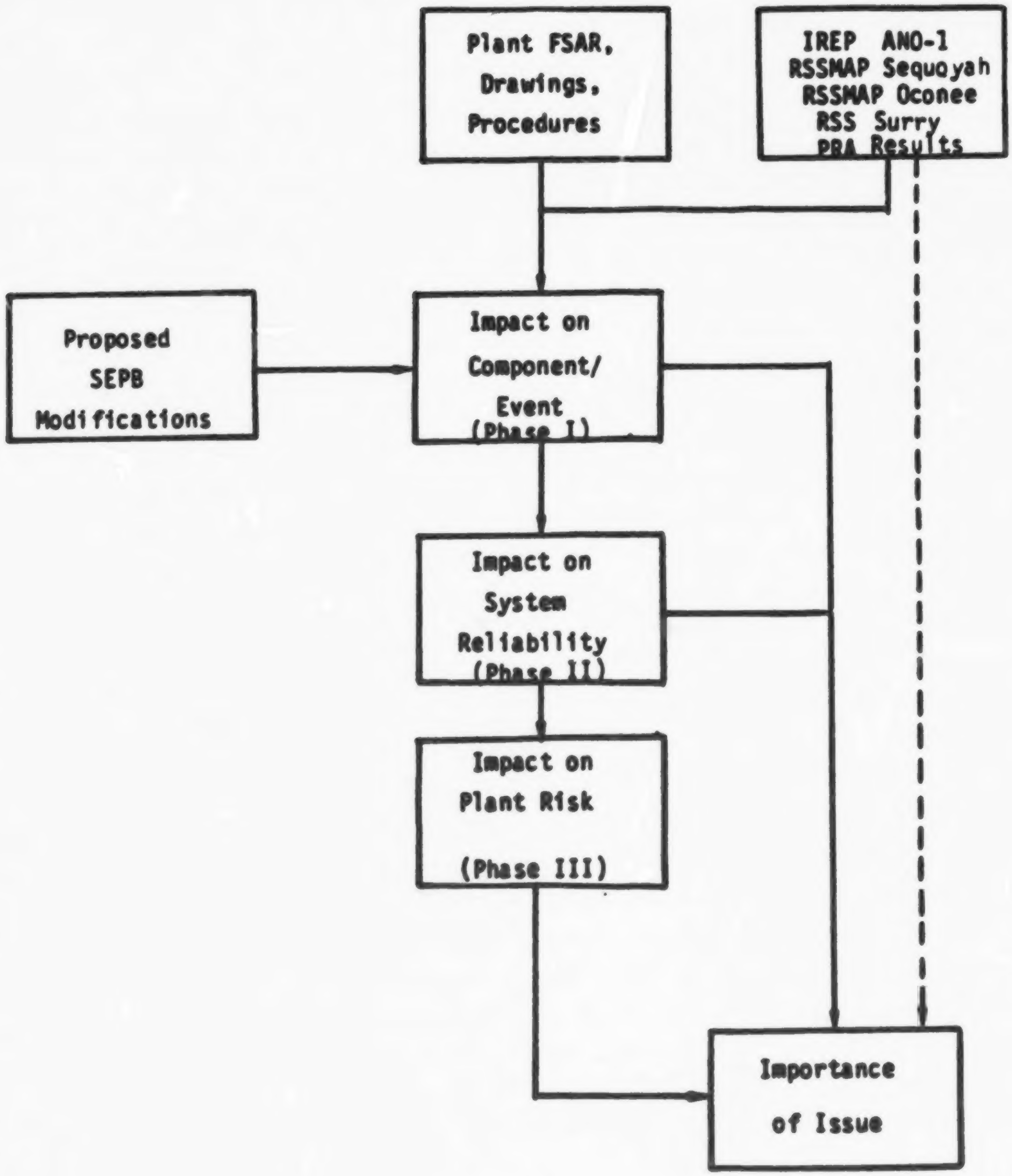
Plant FSAR,
Drawings,
Procedures
IREP ANO-1
RSSMAP Sequoyah
RSSMAP Oconee
RSS Surry
PRA Results
Proposed
SEPB
Modifications
Impact on
Component/
Event
(Phase I)
Impact on
System
Reliability
(Phase II)
Impact on
Plant Risk
(Phase III)
Importance
of Issue

Figure 1. Study Methodology

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Table 1

Classification of Issues

Classification	Criterion
High	Resolution of issue dominates value of the top event of a dominant fault tree or dominant sequence event.
Medium	Resolution of issue impacts but does not dominate value of top event of dominant fault tree or dominant sequence event.
Low	Resolution of issues has no impact on value of top event of dominant fault tree or dominant sequence event.

III. Results

There were 39 issues identified by the Systematic Evaluation Program Branch for the San Onofre Nuclear Power Plant. Of these, 17 were outside the scope of our analysis and 22 were within our scope. Of the 22 issues which were within the scope of our analysis, there were 2 issues that were completely resolved by the SEP Branch before the start of our study, and 2 that were completely resolved before completion of the final report. Table 2 gives those issues we did not analyze and Table 3 gives those issues we did analyze.

Each issue was analyzed for classification by the criteria described in the previous section of this report. That is, we assessed whether resolution of the issue would affect the fault trees which were developed for the particular issue at San Onofre and quantified the effect. The fault trees were examined to determine the resulting change in the top event(s), and other PWR PRAs were reviewed to characterize the affected fault trees by whether they would be part of dominant accident sequences.

Table 4 presents the results of our analysis. For each issue, the system or accident event that the issue potentially impacts, the change in unavailability due to resolution of the issue and the component or system for which this was calculated (Phase I), whether the issue affects the top event of the fault tree(s)/event(s), whether the fault tree(s) or event(s) affected would appear in any dominant accident sequences (Phase III), and, based on applying thecriteria of Section II to all of the above results, the resulting classification of the issues are given. Table 5 gives a list of the classifications of the issues as high, medium, or low importance to risk. A discussion of the classification of each issue is given in the Executive Summary of this report.

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Table 2

SEP Issues Not Evaluated

1.	II-1.C	Potential Hazards or Changes in Potential Hazards due to Transportation, Institutional, Industrial, and Military Facilities
2.	II-3.A	Hydrological Description
3.	II-3.B	Flooding Potential and Protection Requirements
4.	II-3.B.1	Capability of Operating Plants to Cope With Design Basis Flood Conditions
5.	II-4.F	Settlement of Foundations and Buried Equipment
6.	III-1	Quality Group Classification of Components and Systems
7.	III-2	Wind and Tornado Loadings
8.	III-3.A	Effects of High Water Level on Structures
9.	III-3.C	Inservice Inspection of Water Control Structures
10.	III-4.A	Tornado Missiles
11.	III-7.B	Design Codes, Design Criteria, Load Combinations and Reactor Cavity Design Criteria
12.	III-10.B	Pump Flywheel Integrity
13.	V-6	Reactor Vessel Integrity
14.	VI-1	Organic Materials and Post-Accident Chemistry

Table 2 (continued)
SEP Issues Not Evaluated

15.	VI-6	Containment Leak Testing
16.	VIII-1.A	Potential Equipment Failures Associated with Degraded Grid Voltage
17.	XV-1	Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

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Table 3

SEP Issues Evaluated

1.	III-8.A	Loose Parts Monitoring and Core Barrel Vibration Monitoring
2.	III-10.A	Thermal - Overload Protection for Motors of Motor-Operated Valves
3.	IV-2	Reactivity Control Systems Including Functional Design and Protective Against Single Failures
4.	V-5**	Reactor Coolant Pressure Boundary (RCPB) Leakage Detection
5.	V-10.A	RHR Heat Exchanger Tube Failures
6.	V-10.B*	RHR Reliability
7.	V-11.A	Requirements for Isolation of High and Low Pressure Systems
8.	V-11.B	RHR Interlock Requirements
9.	VI-4	Containment Isolation System
10.	VI-7.A.3*	ECCS Actuation System
11.	VI-7.B	ESF Switchover from Injection to Recirculation Mode (Automatic ECCS Realignment)
12.	VI-7.C.2	Failure Mode Analysis ECCS
13.	VI-10.A	Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing

Table 3 (continued)
SEP Issues Evaluated

14.	VII-1.A	Isolation of Reactor Protection System Non-Safety Systems, Including Qualifications of Isolation Devices
15.	VII-2+	Engineered Safety Features (ESF) System Control Logic and Design
16.	VII-3	Systems Required for Safe Shutdown
17.	VIII-3.B	DC Power System Bus Voltage Monitoring and Annunciation
18.	VIII-4	Electrical Penetrations of Reactor Containment
19.	IX-3	Station Service and Cooling Water Systems
20.	IX-5	Ventilation Systems
21.	XV-2	Spectrum of Steam System Piping Failure Inside and Outside of Containment (PWR)
22.	XV-7+	Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

*This issue was resolved by the SEP Branch prior to this evaluation.
**Final SER not available for analysis
+These issues, although analyzed, were completely resolved before completion of the final report.

Table 4

Results of Analysis

Issue	Event/Component	Affects Event/Component	Affects System Unavailability	Affects Core Melt Risk	Dominant or Non Dominant Contributor	Risk Significance
III - 8.A	Transients	No	-	-	-	Low
III - 10.A	Valves	No	-	-	-	Low
IV - 2	Transients	No	-	-	-	Low
V - 10.A	Primary Leakage to Environment	No	-	-	-	Low
V - 11.A	LOCA Outside Containment					
	(a) CVCS	No	-	-	-	Low
	(b) Long Term Recirculation	No	-	-	-	Low
	(c) SIS	Yes	-	Yes	Non-DOM	Medium
V - 11.B	LOCA Outside Containment	No	N/A	-	-	Low
VI - 4	Containment Integrity	No	-	-	-	Low
VI - 7.B	ESF Switchover	Yes	Yes	Yes	Non-DOM	Medium
VI - 7.C.2	ECCS	Yes	Yes	Yes	Non-DOM	Medium
VI - 10.A	RPS sensors/ relays	No	-	-	-	Low
VII - 1.A	RPS sensor channels	Yes	No	-	-	Low
VII - 3	RHRS MOVs	No	-	-	-	Low
VIII - 3.B	DC Power Supplies	Yes	Yes	Yes	Non-DOM	Medium
VIII - 4	Containment Isolation	No	-	-	-	Low
IX - 3	Passive Failures	No	-	-	-	Low
IX - 5	(a) Reactor Auxiliary Building	No	-	-	-	Low
	(b) Station Battery Room	Yes	Yes	Yes	DOM	High
	(c) 480V Switchgear Room Ventilation	Yes	Yes	No	-	Low
	(d) Cable Spreading Area Ventilation	Yes	Yes	Yes	DOM	High
XV - 2	Offsite Consequences	No	-	-	-	Low

TABLE 5

Classification of Issues
Importance to Risk

High	
IX - 5	Ventilation Systems
Medium	
V - 11.A	Requirements for Isolation of High and Low Pressure Systems
VI - 7.B	ESF Switchover from Injection to Recirculation Mode (Automatic ECCS Realignment)
VI - 7.C.2	Failure Mode Analysis ECCS
VIII - 3.B	DC Bus Voltage Monitoring
Low	
III - 8.A	Loose Parts Monitoring
III - 10.A	Thermal Overload Protection for Motors of Motor Operated Valves
IV - 2	Reactivity Control System Including Functional Design and Protection Against Single Failure
V - 10.A	Residual Heat Removal System Heat Exchanger Tube Failure
V - 11.B	RHR Interlock Requirements
VI - 4	Containment Isolation System
VI - 10.A	Response Time Testing
VII - 1.A	RPS Isolation
VII - 3	Systems Required for Safe Shutdown
VIII - 4	Electrical Penetrations of Reactor Containment
IX - 3	Station Service and Cooling Water Systems
XV - 2	Spectrum of Steam System Piping Failure Inside and Outside of Containment
Resolved	(These issues were analyzed for the draft, but completely resolved by the time the final report was completed.)
VII - 2	Engineered Safety Features (ESF) System Control Logic and Design
XV - 7	Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

IV. Analysis

Following is the analysis for each topic to determine its importance to risk.

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III-8.A Loose-Parts Monitoring and Core Barrel Vibration Monitoring

1. NRC Evaluation

A loose-parts monitoring system as required by Regulatory Guide 1.133 does not exist at San Onofre.

2. NRC Recommendations

Install a loose-parts monitoring system to detect loose parts in the Reactor Coolant Pressure Boundary.

3. Systems Affected

Loose parts can cause transient events by causing damage within the reactor coolant system.

4. Comments

None

5. Analysis

The only concern, from a risk perspective, of loose parts is that they may cause a transient which challenges the plant and its safety systems. There is ample data on transients to show that the contribution of this initiator to the total frequency of initiation of a transient is negligible. That is, because the historical transient rate is so high, several per reactor year, and the historical contribution to this frequency by loose parts has been negligible. Eliminating loose-parts-induced transients will have no effect on the transient frequency and no effect on risk.

6. Conclusions

Eliminating loose-parts-induced transients by installing a loose-parts monitoring system would have no effect on risk. We therefore rank the risk significance of this issue as low.

III-10.A Thermal Overload Protection for Motors of Motor-Operated Valves (MOVs)

1. NRC Evaluation

Thermal overload protection for MOVs should be bypassed, under accident conditions, by ECCS signals. Also, trip set points should be set high enough to prevent spurious trips due to certain conditions such as (a) variations in the ambient temperature, (b) inaccuracies in the design of the thermal overload device, and (c) setpoint drift. At San Onofre 1, it was found that the thermal overload device of four MOVs do not meet the above requirements.

2. NRC Recommendation

Thermal overload protection for the above MOVs should be modified such that it is bypassed when an ECCS signal is received.

3. Systems Affected

Of the four MOVs having unbypassed thermal overload devices, two (MOVs 813 & 814) are identified in the Residual Heat Removal System but they are not required to change their state during or following an accident. Therefore, it is judged that the function of these two valves are not affected by any failure of the thermal overload protection device.

The remaining unbypassed MOVs (720 A & B) are associated with the Component Cooling Water System. Thus, failure of either of these two MOVs will affect the Component Cooling Water System (CCWS) and all the components and systems that are dependent on CCWS for heat removal.

4. Comments

The concern in this issue is that a spurious trip of a thermal overload protection device could cause a safety-related valve not to open during accident conditions, even though nothing is wrong with the valve. However, by bypassing the thermal overload protection, the danger of damaging the valve increases, and this reduces the possibility of recovering the

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operability of the valve. This negative effect on system reliability will not be addressed.

5. Analysis

This analysis will address the reliability of a valve both with and without thermal overload bypass. The failure rate per demand of a motor-operated valve can be found in Appendix III of the Reactor Safety Study (WASH-1400) on Table III-2-1; this failure rate is

$$\lambda_D(MOV) = 1 \times 10^{-3}/d,$$

and is a combined failure rate; that is, it represents valve failure from all modes. This implies that failures due to unbypassed thermal overloads are included in the failure rate.* Therefore, the failure rate for the MOVs with unbypassed thermal overloads is

$$\lambda_D(MOV/NOBY) = 1 \times 10^{-3}/d$$

In order to determine the failure rate of valves with their thermal overload devices bypassed, it is necessary to find out the contribution of thermal overload device failure to the valve failure rate.

The failure rate per hour of a thermal relay (common quality, ground-fixed environment) can be found in Section 1, Nonelectronic Parts Reliability Data (NPRD-2). The failure rate is

$$\lambda_S(TS) = 4 \times 10^{-7}/hr.$$

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*It is valid to say this since thermal overload devices are seldom, if ever, bypassed during test.

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In order to determine the demand failure rate, it is necessary to have a test interval. In WASH-1400, demand failure rate for MOVs is based on monthly testing, thus the number of hours in a month (720) will be applied to the equation

$$\lambda_D = \frac{\lambda_S \tau}{}$$

where τ is the test interval. This equation gives

$$\lambda_{D(TR)} = \frac{(4\text{x}10^{-7}/\text{hr})(720\ \text{hr/months})}{} = 1.4\text{x}10^{-4}/\text{d}$$

Thus the demand failure rate of a valve with the thermal overload bypassed is

$$\lambda_D(\text{MOV/BY}) = \lambda_D(\text{MOV/NOBY}) - \lambda_D(\text{TR}) = 1.0\text{x}10^{-3}/\text{d} - 1.4\text{x}10^{-4}/\text{d}$$

$$= 8.6\text{x}10^{-4}/\text{d},$$

or approximately a 14 percent decrease in the valve failure rate by bypassing the thermal overload.

As was mentioned earlier the two motor operated valves of concern, namely MOVs 720A & 720B, are associated with the Component Cooling Water System (CCWS). During normal operation, only one heat exchanger and one pump are necessary to carry the designed load. This is also true for plant cooldown condition or other abnormal conditions although both heat exchangers and all three pumps are normally used to expedite heat removal. For this issue, the first configuration where only one heat exchanger and one pump are required is analyzed.

Figure III-10.A-1 shows a simplified diagram of the Component Cooling Water System. To evaluate the effect of the MOVs with and without thermal overload bypass on the availability of the CCWS a fault tree for this system was developed and is shown in Figure III-10.A-2. According to Figure III-10.A-1, MOV 720A is normally open, while MOV 720B is normally closed. Thus, failure of the thermal overload protection device would not affect the operation of MOV 720A during abnormal conditions since it does not change the position under these circumstances. The fault tree shown in Figure

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III-10.A-2 is next quantified using the data shown in Table III-10.A-1 (WASH-1400). The unavailability of the CCWS is $1.95x10^5$. Removal of the thermal overload bypass from MOV 720B has no noticeable effect on the unavailability of this system.

6. Conclusion

The above analysis shows that, although bypassing the thermal overload protection device of MOV does reduce the demand failure rate of the valve, such action would not significantly change the probability of failure of the affected system. Therefore, the risk significance of this issue is ranked low.

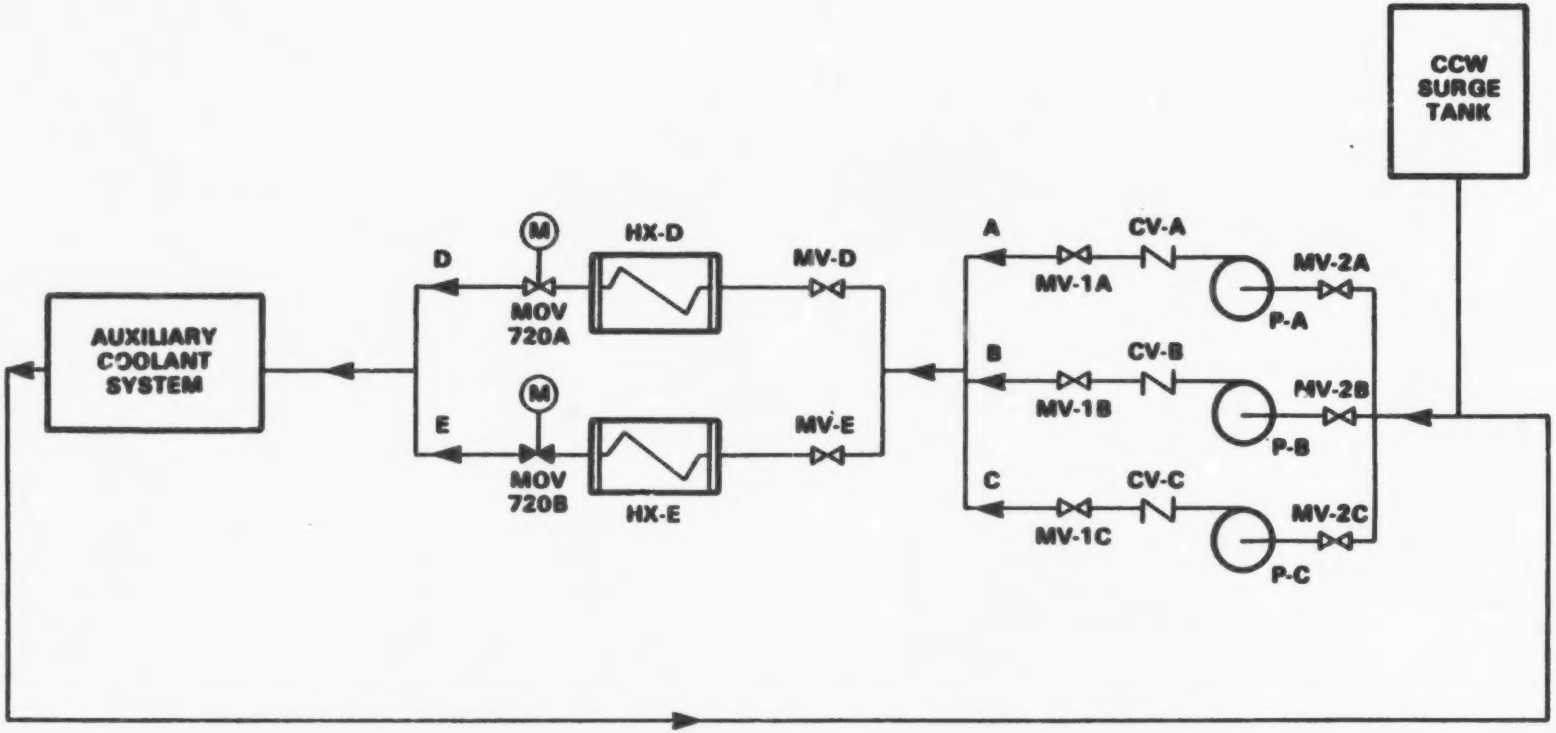
CCW
SURGE
TANK
A
CV-A
MV-2A
MV-1A
P-A
B
CV-B
MV-2B
MV-1B
P-B
C
CV-C
MV-2C
MV-1C
P-C
HX-D
MV-D
D
M
MOV
720A
E
M
MOV
720B
HX-E
MV-E
AUXILIARY
COOLANT
SYSTEM

Figure III-10.A-1. SIMPLIFIED SCHEMATIC OF THE COMPONENT COOLING WATER SYSTEM

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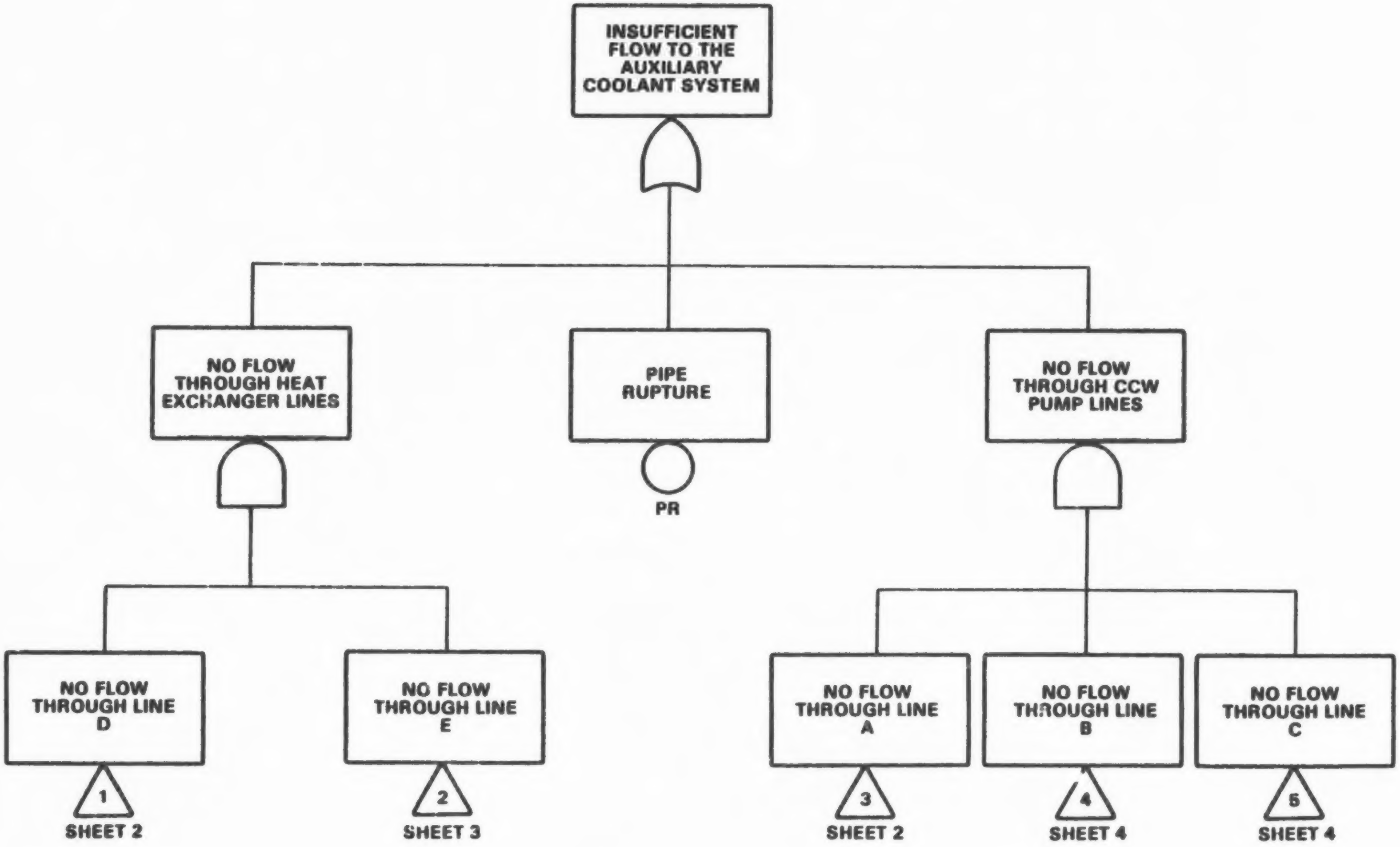
INSUFFICIENT FLOW TO THE AUXILIARY COOLANT SYSTEM
NO FLOW THROUGH HEAT EXCHANGER LINES
PIPE RUPTURE
PR
NO FLOW THROUGH CCW PUMP LINES
NO FLOW THROUGH LINE D
1
SHEET 2
NO FLOW THROUGH LINE E
2
SHEET 3
NO FLOW THROUGH LINE A
3
SHEET 2
NO FLOW THROUGH LINE B
4
SHEET 4
NO FLOW THROUGH LINE C
5
SHEET 4

Figure III-10.A-2. FAULT TREE FOR THE EVENT "INSUFFICIENT FLOW TO THE AUXILIARY COOLANT SYSTEM"

SHEET 1

253

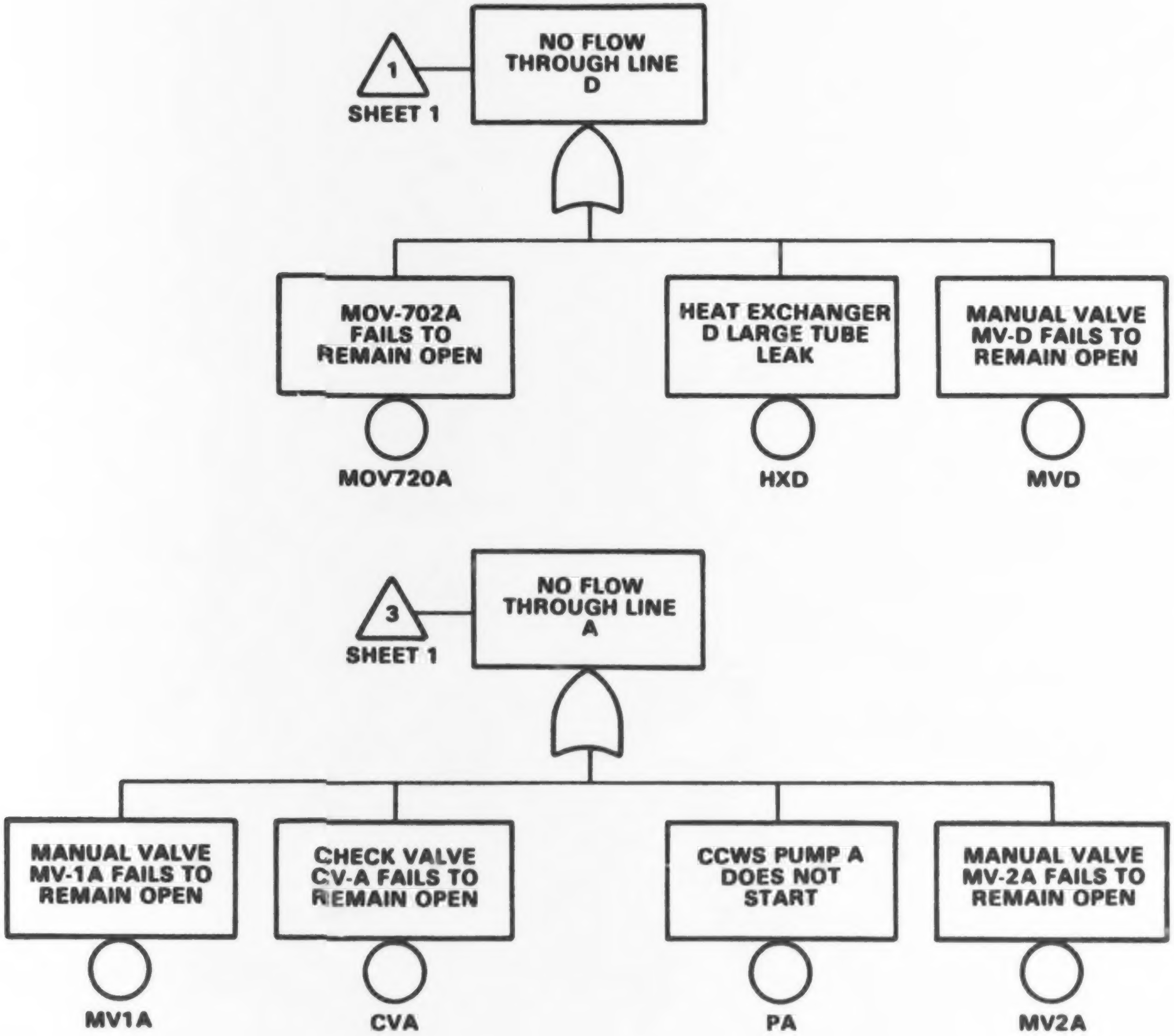
1
SHEET 1
NO FLOW THROUGH LINE D
MOV-702A FAILS TO REMAIN OPEN
MOV720A
HEAT EXCHANGER D LARGE TUBE LEAK
HXD
MANUAL VALVE MV-D FAILS TO REMAIN OPEN
MVD
3
SHEET 1
NO FLOW THROUGH LINE A
MANUAL VALVE MV-1A FAILS TO REMAIN OPEN
MV1A
CHECK VALVE CV-A FAILS TO REMAIN OPEN
CVA
CCWS PUMP A DOES NOT START
PA
MANUAL VALVE MV-2A FAILS TO REMAIN OPEN
MV2A

Figure III-10.A-2. (CONTINUED)

SHEET 2

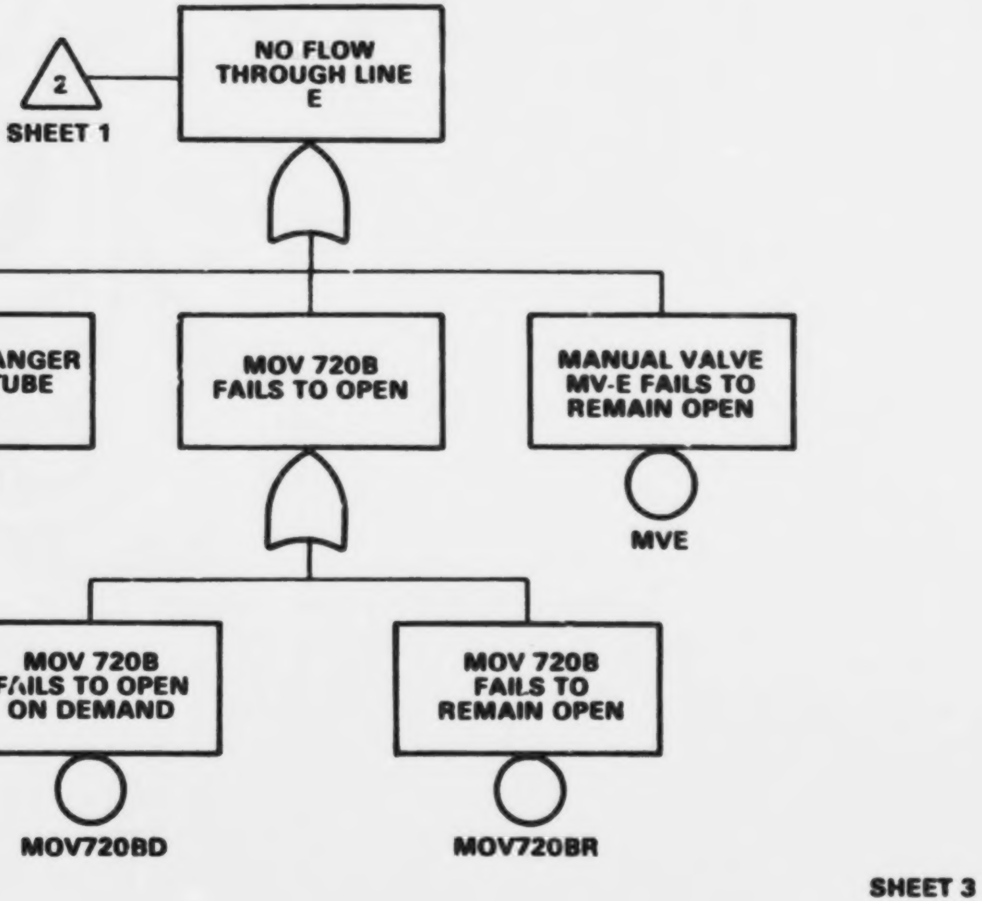
2
SHEET 1
NO FLOW THROUGH LINE E
HEAT EXCHANGER E LARGE TUBE LEAK
MOV 720B FAILS TO OPEN
MANUAL VALVE MV-E FAILS TO REMAIN OPEN
HXE
MVE
MOV 720B FAILS TO OPEN ON DEMAND
MOV 720B FAILS TO REMAIN OPEN
MOV720BD
MOV720BR
SHEET 3

Figure III-10.A-2. (CONTINUED)

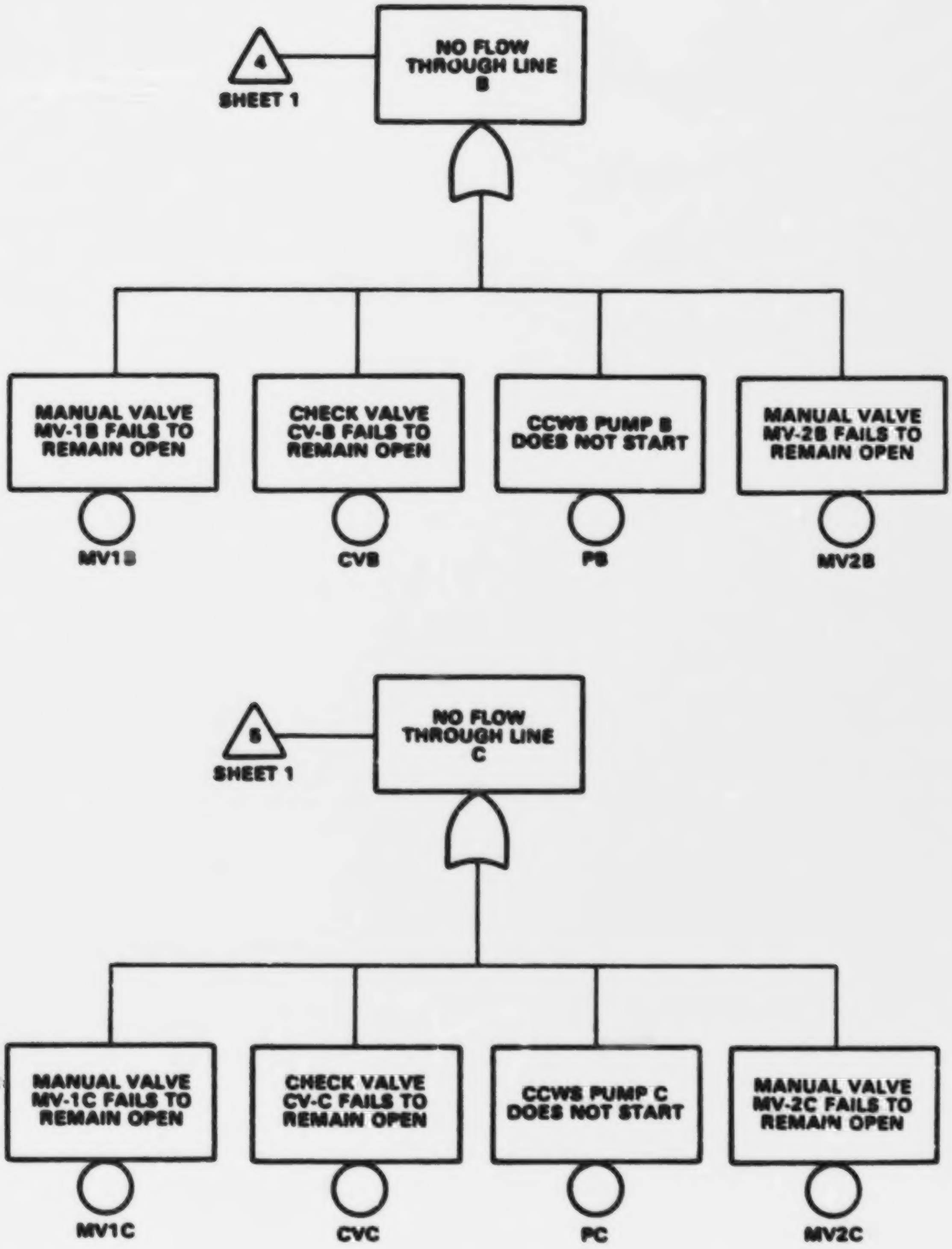
4
SHEET 1
NO FLOW THROUGH LINE B
MANUAL VALVE MV-1B FAILS TO REMAIN OPEN
CHECK VALVE CV-B FAILS TO REMAIN OPEN
CCWS PUMP B DOES NOT START
MANUAL VALVE MV-2B FAILS TO REMAIN OPEN
MV1B
CVB
PB
MV2B
5
SHEET 1
NO FLOW THROUGH LINE C
MANUAL VALVE MV-1C FAILS TO REMAIN OPEN
CHECK VALVE CV-C FAILS TO REMAIN OPEN
CCWS PUMP C DOES NOT START
MANUAL VALVE MV-2C FAILS TO REMAIN OPEN
MV1C
CVC
PC
MV2C

Figure III-10.A-2. (CONTINUED) SHEET 4

Table III-10.A-1 Failure Rates for Various Faults Shown on Figure III-10.A-2

Fault Identifier	Failure Mode	Failure Rate	Fault Duration (Hours)	Unavailability	Comments
MV1A,MV1B, MV1C,MVD, MVE,MV2A, MV2B,MV2C	Manual valve fails to remain open	1.0×10^{-4}/D	-	1.0×10^{-4}	
MOV720B	Motor operated valve does not open on demand	1.0×10^{-3}/D	-	1.0×10^{-3}	Thermal overload unbypassed
				8.6×10^{-4}	Thermal overload bypassed
MOV720AR, MOV720BR	Motor operated valve fails to remain open	1.0×10^{-4}/D	-	1.0×10^{-4}	
CVA,CVB,CVC	Check valve fails to remain open	1.0×10^{-4}/D	-	1.0×10^{-4}	
HXD,HXE	Heat exchanger large tube leak	3.0×10^{-8}/Hr	6570	1.9×10^{-4}	Failure rate, upper bound of small pipe rupture. Fault duration, every refueling.
PA,PB,PC	Pump does not start	1.0×10^{-3}/D	-	1.0×10^{-3}	
PR	Pipe rupture	3.0×10^{-9}/Hr	6570	1.9×10^{-5}	Failure rate, upper bound of large pipe rupture. Fault duration, every refueling.

IV-2 Reactivity Control Systems Including Functional Design and Protective Against Single Failures

1. NRC Evaluation

General Design Criteria (GDC) 25 requires that no single failure of reactor protection system such as rod withdrawal would result in reactivity and power increases that could exceed fuel design limits. The reactivity control system does not have to meet a single failure criteria. In San Onofre Nuclear Power Plant it was found that single failures in the reactivity control system could result in malfunctions such as two banks or subgroups of control rods moving out instead one or a subgroup bank or banks of control rod moving out inadvertently. Additionally, other malfunctions such as lack of control rod movement upon rod withdrawal command or inadvertent rod drops were also postulated as a result of a single failure.

2. NRC Recommendations

No specific recommendation was provided except that the particular events mentioned above must be considered in the evaluation of SEP Topic XV-8.

3. Systems Affected

The only system affected by this issue is the reactivity control system.

4. Comments

Rod withdrawal accidents are contributors to the frequency of initiation of transients in the lightwater reactors. As long as the mitigating systems designed to mitigate the consequences of these transients function correctly, no core melt and consequently risk to the public would result. The most important mitigating system in case of rod withdrawal accidents that must function first is the reactor protection or scram system.

5. Analysis

The only accidents of concern following a single failure in the reactivity control system is the rod withdrawal accidents. Other malfunctions that result in the blocking of the rod withdrawal or dropping of the rods in the core cannot lead to large reactivity insertions that could result in a core melt accident if the reactor protection system fails. The most important consequence of rod withdrawal accident is local power peaking in the vicinity of the region where the rod has been withdrawn. Following this power increase various mechanisms designed to detect this localized power peaking will initiate a reactor trip. Some cladding damage in the fuel bundles that are in the vicinity of the control rods that have been withdrawn would be expected due to sudden increase in the local power production. But no fuel melting or damage is expectead in these fuel bundles. Previous comprehensive Probabilistic Risk Assessments such as WASH-1400 have shown that the most significant contribution to the risk due to operation of a Nuclear Power Plant is from accidents that involve core meltdown. Consequently rod withdrawal accidents which do not lead to core meltdown are not considered risk significant.

6. Conclusion

Single failures in the reactivity protection system do not have a significant effect on the overall risk due to the operation of the San Onofre Nuclear Power Plant and thus are ranked low from the risk point of view.

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V-10.A Residual Heat Removal Heat Exchanger Tube Failures

1. NRC Evaluation

The San Onofre nuclear reactor plant does not meet the current criteria regarding the monitoring of potential leaks to the environment from the primary cooling system through the component cooling water system into the salt water cooling system.

2. NRC Recommendation

Recommendations are under review by NRC.

3. Systems Affected

The systems affected by this issue are the Primary Coolant System, the Residual Heat Removal System, the Component Cooling Water System, and the Salt Water System.

4. Comments

In the San Onofre Unit 1 the primary side of the Residual Heat Removal System heat exchangers (primary coolant system) is at a pressure of 70-420 psig and the secondary side (Component Cooling Water System) is at 65-75 psig. The pressure differential allows leakage from the primary coolant system into the Component Cooling Water System. The secondary side of the Component Cooling heat exchangers (Salt Water Cooling System) is at 30 psig which is lower than the primary side. This pressure differential allows leakage from the Component Cooling Water System into the Salt Water Cooling System.

During normal plant operation there is little chance for intrusion of chloride and other detrimental impurities that would exist in the salt water system to enter the component cooling water system. The salt water cooling system cools only the component cooling water system and it would be shutdown in case of a component cooling water shutdown. Thus, there is also little chance of leakage of contaminants during component cooling water system shutdown.

At present a radiation monitor alerts operators to leakage from the RHR heat exchangers. The Component Cooling Water System has high and low level alarms on the surge tank to alert operators to leakage into or out of the system. The component cooling water is sampled weekly during the power operation of the plant.

5. Analysis

Based on previous comments the only issue of concern is the possible leakage of primary coolant to the environment via the component cooling and salt water cooling system.

A simplified schematic of the Residual Heat Removal System is presented in Figure V-10.A-1. Figure V-10.A-2 shows a simplified fault tree for the possible leakage paths from the primary coolant system to the environment. As can be seen from the fault tree, one of the two residual heat exchangers and one of the two component cooling heat exchangers must fail while the Residual Heat Removal System is in operation in order for leakage from the primary coolant system to occur. The frequency of leakage from the primary coolant system to the environment is

2(frequency offailure of residual heat exchanger)
x 2(possibility of failure of component cooling heat exchanger).

The frequency of failure of the residual heat exchangers and the component cooling heat exchangers was calculated by using the upper bound for a small diameter pipe break from WASH-1400. This failure rate is $3x10^{-8}$/hr. Assuming a refueling outage every 18 months and consequently testing of the heat exchangers every 18 months, the frequency of failure of the heat exchanger is calculated from the relationship $\lambda T/2$. In this relationship, λ is the failure rate of the component and T is the time between tests. Based on this, the frequency of failure of the heat exchanger is $1.3x10^{-4}$/yr.

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Thus, the frequency of leakage from the primary coolant system to the environment through the Residual Heat Removal System, Component Cooling Water System, and Salt Water Cooling System is conservatively calculated to be:

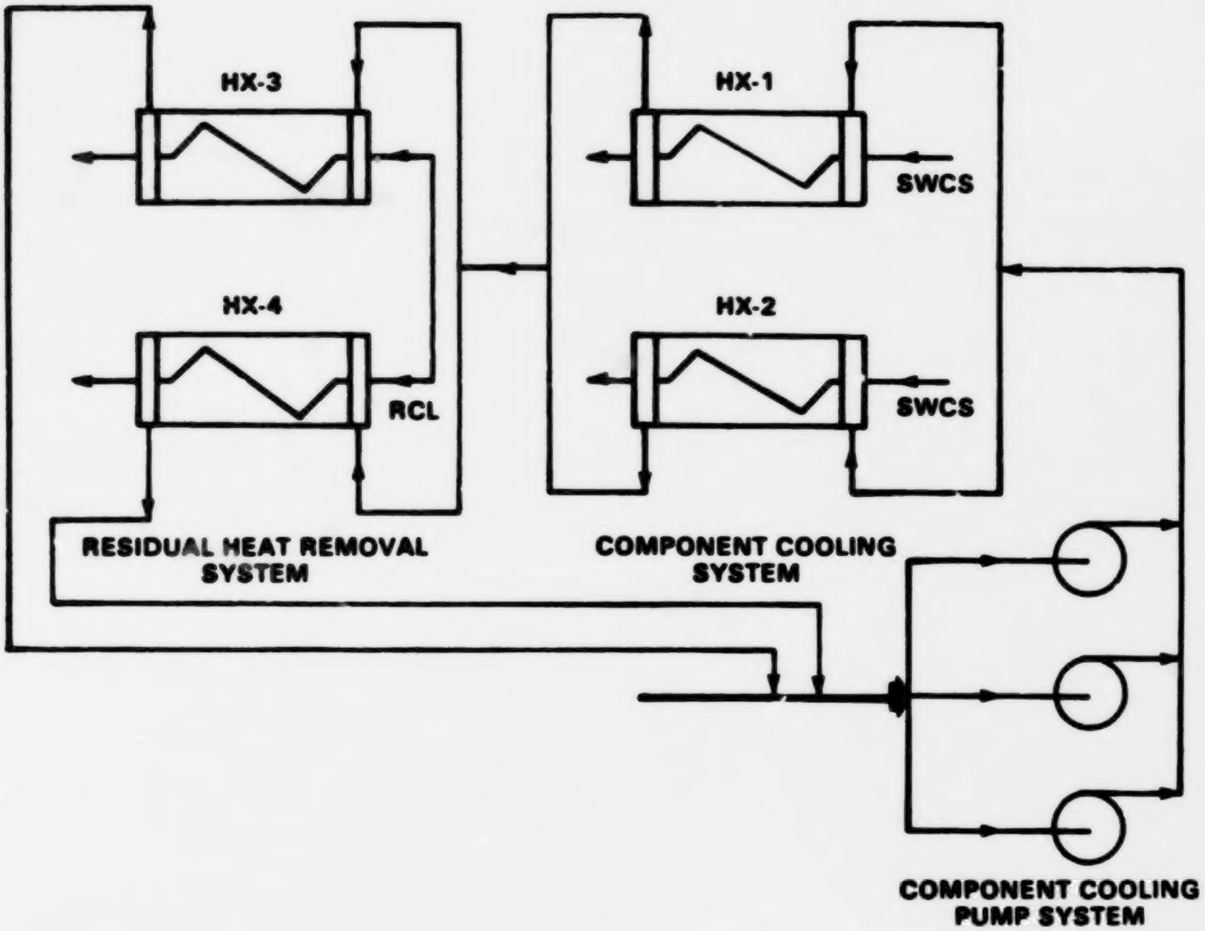
$$2(1.3\times10^{-4}/\text{yr}) \times 2(1.3\times10^{-4})$$

or $6.8\times10^{-8}/\text{yr}$.

Considering the low frequency of this event and the relatively low importance of the consequences of this leakage compared to the consequences of a core melt accident, it is clear that this event should not contribute significantly to the overall risk of the plant.

6. Conclusions

The frequency of a leakage from the primary coolant system to the environment was conservatively calculated to be $6.8\times10^{-8}/\text{yr}$. Considering the consequences of a leakage and the consequences of a core melt accident, it is clear that this event does not have a significant effect on the overall risk due to operation of this plant. Thus, we rank the risk significance of this issue as low.


HX-3
HX-1
SWCS
HX-4
HX-2
RCL
SWCS
RESIDUAL HEAT REMOVAL SYSTEM
COMPONENT COOLING SYSTEM
COMPONENT COOLING PUMP SYSTEM

RCL: REACTOR COOLANT LETDOWN

Figure V-10.A-1. SIMPLIFIED SCHEMATIC OF RESIDUAL HEAT REMOVAL SYSTEM, COMPONENT COOLING SYSTEM AND SALT WATER SYSTEM

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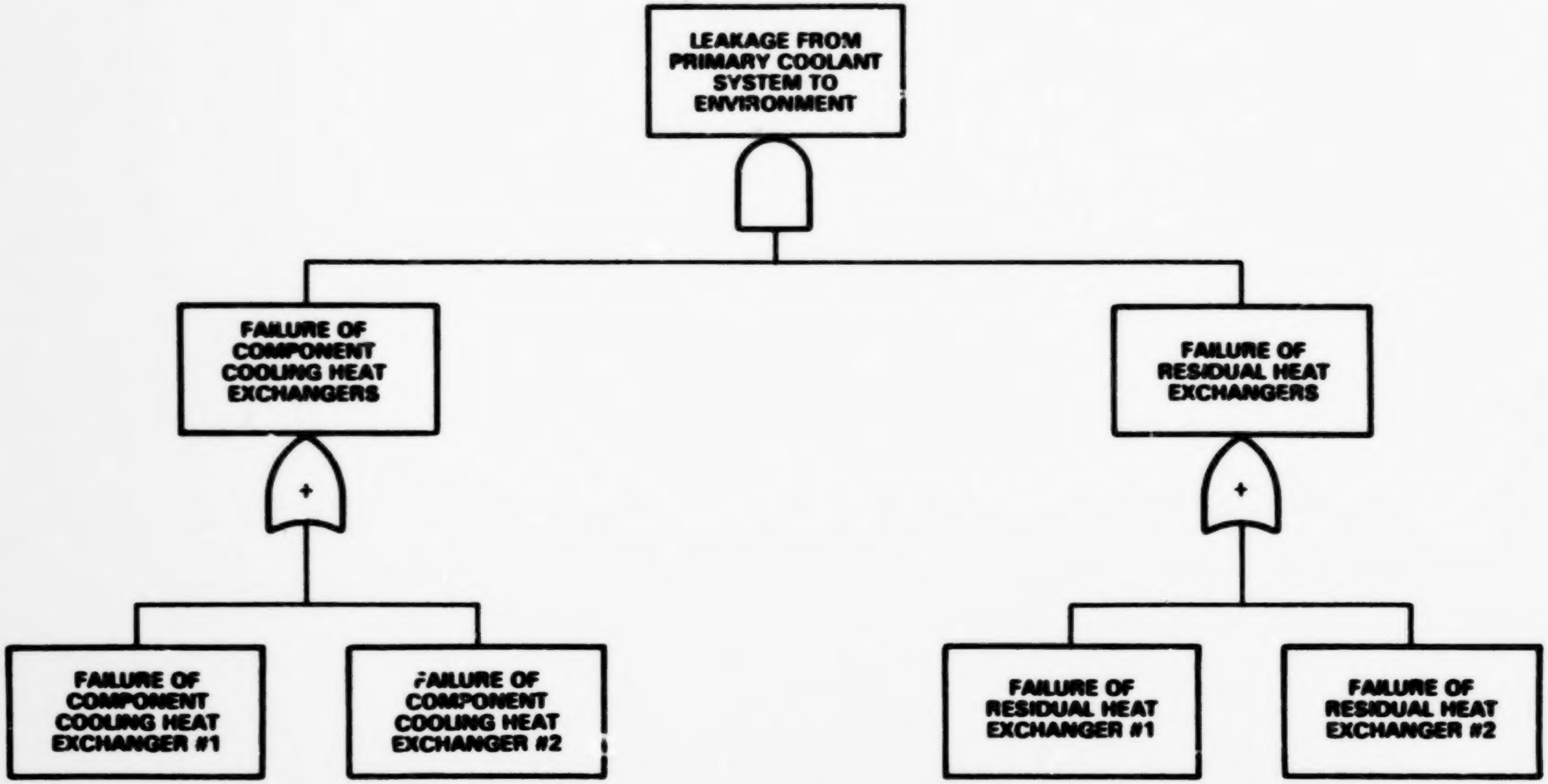
LEAKAGE FROM PRIMARY COOLANT SYSTEM TO ENVIRONMENT
FAILURE OF COMPONENT COOLING HEAT EXCHANGERS
FAILURE OF RESIDUAL HEAT EXCHANGERS
+
+
FAILURE OF COMPONENT COOLING HEAT EXCHANGER #1
FAILURE OF COMPONENT COOLING HEAT EXCHANGER #2
FAILURE OF RESIDUAL HEAT EXCHANGER #1
FAILURE OF RESIDUAL HEAT EXCHANGER #2

Figure V-10.A-2. FAULT TREE FOR THE EVENT "LEAKAGE FROM PRIMARY COOLANT SYSTEM TO ENVIRONMENT"

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V-11.A Requirements for Isolation of High and Low Pressure Systems

1. NRC Evaluation

At San Onofre Unit 1 there are three systems connected to the reactor coolant system (RCS) that have a lower design pressure rating than the RCS. These three systems are the residual heat removal system (RHRS), the safety injection system (SIS) and the chemical and volume control system (CVCS). For these systems the following conditions do not meet current criteria regarding isolation of low pressure systems.

1. None of the RHR system isolation valves automatically close if RCS pressure increases above RHR system design pressure, and the outboard isolation valves have no pressure-related interlocks as required by Branch Technical Position (BTP) RSB-5-1. The interlocks for the inboard isolation valves are neither diverse nor independent.
2. The safety injection system and long-term recirculation system motor-operated isolation valves have no pressure-related interlocks required by Standard Review Plant (SRP) 6.3.
3. The chemical and volume control system isolation valves have no pressure-related interlocks as required by BTP EICSB-3.

2. NRC Recommendation

Modification of the RHR system is not necessary until the low temperature overpressurization protection review is completed. The SIS and long-term recirculation system motor-operated isolation valves should be modified to satisfy the review criteria of SRP 6.3 or an acceptable check valve test program should be implemented. The modification is recommended due to the severe consequences of a LOCA outside the containment.

The CVCS discharge isolation valves should be modified to satisfy BTP EICSP-3 or a redundant relief valve should be installed or demonstrate that a break in this line will not violate 10 CFR 100 limits.

3. Systems Affected

The systems affected by this issue are the safety injection system (SIS), the long-term recirculation system, and the chemical and volume control system (CVCS).

4. Comments

The adequacy of the overpressurization protection on the safety injection system, the long-term recirculation system, and the chemical and volume control system will be evaluated in this issue. The RHRS interlock requirements are addressed in topic V-11.B.

5. Analysis

Figure V-11.A-1 shows the simplified schematic of the CVCS during normal operation. The concern about the discharge line of the CVCS is that given reverse flow past the check valves, if the CVCS pumps are not running the low pressure piping of the CVCS could be exposed to the high pressure reactor coolant and a LOCA outside containment might occur. To find the probability of this scenario a simplified fault tree for the event "Reverse Leakage of RCS to the Charging Pumps" was developed and is shown in Figure V-11.A-2. This fault tree was next quantified using the data shown in Table V-11.A-1. The probability of reverse leakage and initiation of a LOCA based on the assumptions given in Table V-11.A-1 is 9.4×10^{-7}.

The safety injection system (SIS) consists of two loops which draw water from Refueling Water Storage Tank (RWST) and inject to all three cold legs through a common header. Figure V-11.A-3 shows a simplified schematic of this system. The concern in this case again, is possibility of reverse leakage past the feedwater pumps.

For a leakage path to exist in the safety injection system one of the motor operated valves must be open along with the failure of one check valve on the same injection line since the piping after MOV's is only qualified for 1500 psi of pressure.

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The inadvertent opening of any of the three motor operated valves during normal operation is an extremely unlikely event. A more credible scenario consists of opening of these valves during refueling for tests and the human error in failing to close them after the reactor is taken back to power. The frequency of this event is less than one per year since refueling at San Onofre is performed approximately every 18 months. But for the present calculations this frequency is conservatively assumed to be one per year.

The probability of initiation of a LOCA due to this scenario can be represented as:

$$F \cdot HE \cdot (CV4 + CV5 + CV6)$$

where F = frequency of initiation of the scenario (once a year)
HE = human error in failure to close the MOVs
CV4 = injection line check valve failure probability
CV5 = injection line check valve failure probability
CV6 = injection line check valve failure probability

Using the data shown in Table V-11.A-1, the probability of reverse leakage and possible LOCA outside the containment in this case is 1.7×10^{-5}/year. To reduce this frequency of initiation of a possible LOCA, two improvements to the system can be suggested. The first improvement is to add a pressure interlock to the MOV's. In this case if after refueling these MOV's are left open and the reactor is brought to power, the increase in coolant pressure would automatically result in closure of the MOV's before the pressure is too high to damage the system. Based on a pressure sensor failure probability of 2.7×10^{-7} per hour (WASH-1400) and testing of the pressure sensor in every refueling outage, i.e., an exposure time of 6570 hours, the probability of failure of the pressure sensor is 1.7×10^{-3}. This reduces the frequency of a possible LOCA outside containment to 2.8×10^{-8} per year. An alternative to this modification is to try to reduce the probability of human error in leaving the MOV's open. This can be done by requiring a separate person to check the position of the MOV's using a written checklist before the reactor is taken back to power. In this case, the probability of failure to detect the original error can conservatively

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be assumed to be 0.1 (NUREG/CR-1278, Table 20-9). This reduces the frequency of initiation of a LOCA outside containment to 1.7×10^{-6} per year.

For the long term recirculation system, leakage past the check valves on the charging side of the charging pumps designated as CV9 and CV10 and shown in Figure V-11.A-4 is the top event analyzed. The initiation of this scenario is similar to the last case except that in this case there are two sets of motor operated valves, namely MOV 356, 357, 358 and MOV 18, 19 that must be left open after test during refueling.

Assuming the tests on the two sets of MOVs are performed separately, the probability of initiation of a LOCA due to this scenario can be represented as:

$$F \cdot HE1 \cdot HE2 \cdot (CV9 + CV10)$$

where

F = frequency of initiation of the scenario (once a year)
HE1 = human error in failure to close the first set of MOVs
HE2 = human error in failure to close the second set of MOVs
CV9 = check valve failure probability
CV10 = check valve failure probability

Using the data shown in Table V-11.A-1, the probability of reverse leakage in this case is 7.0×10^{-7}/year.

6. Conclusions

The probability of initiation of a LOCA leading to a core meltdown due to reverse leakage in the CVCS, SIS and long term recirculation system was analyzed. For the CVCS and long-term recirculation system the probability of this event is 9.4×10^{-7} and 7.0×10^{-7} per year respectively. This probability for the SIS is 1.7×10^{-5}. To reduce the frequency of reverse leakage in the SIS, two modifications were analyzed. The first one consists of addition of a pressure interlock to the MOV's. This will reduce the frequency of reverse leakage to 2.8×10^{-8} per year. An alternative to this is to add a written procedure for the checking of the status of these MOV's before the reactor is taken back to power. This will reduce the frequency of the reverse leakage to 1.7×10^{-6} per year. Considering the very conservative assumptions used in defining the scenarios for these calculations and the low frequency of the results, the probability of a core melt accident due to the reverse leakage in the CVCS and long-term recirculation systems does not contribute significantly to the overall risk due to operation of this plant and thus are ranked low from a risk point of view. In case of SIS, the current configuration results in a relatively high frequency of initiation of a LOCA outside containment. Thus, the importance of the SIS reverse leakage is ranked medium with respect to the risk associated with the operation of this plant.

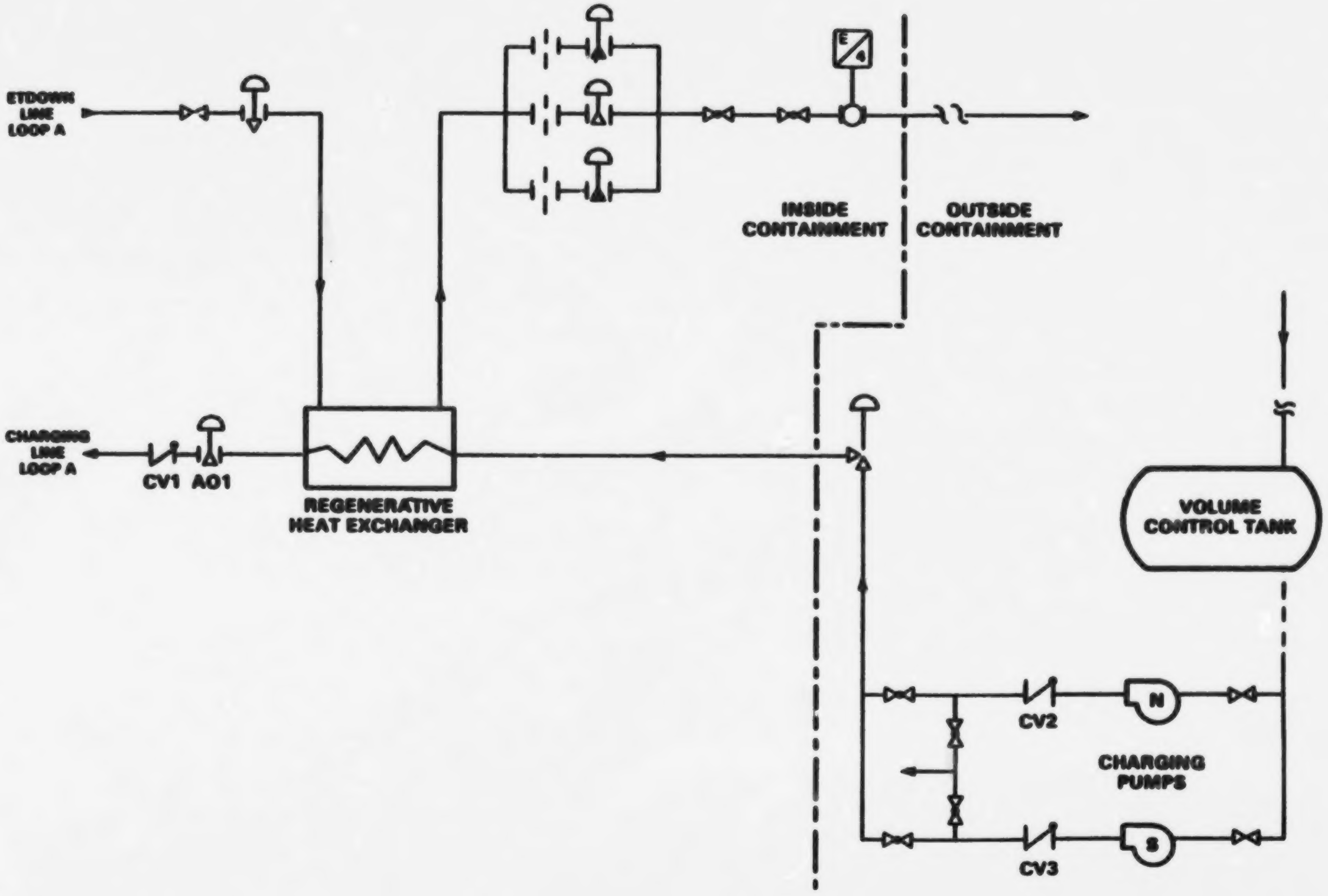
ETDOWN LINE LOOP A
E 4
INSIDE CONTAINMENT
OUTSIDE CONTAINMENT
CHARGING LINE LOOP A
CV1
AO1
REGENERATIVE HEAT EXCHANGER
VOLUME CONTROL TANK
N
CV2
CHARGING PUMPS
S
CV3

Figure V-11.A-1. SIMPLIFIED SCHEMATIC OF THE CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS) DURING NORMAL OPERATION

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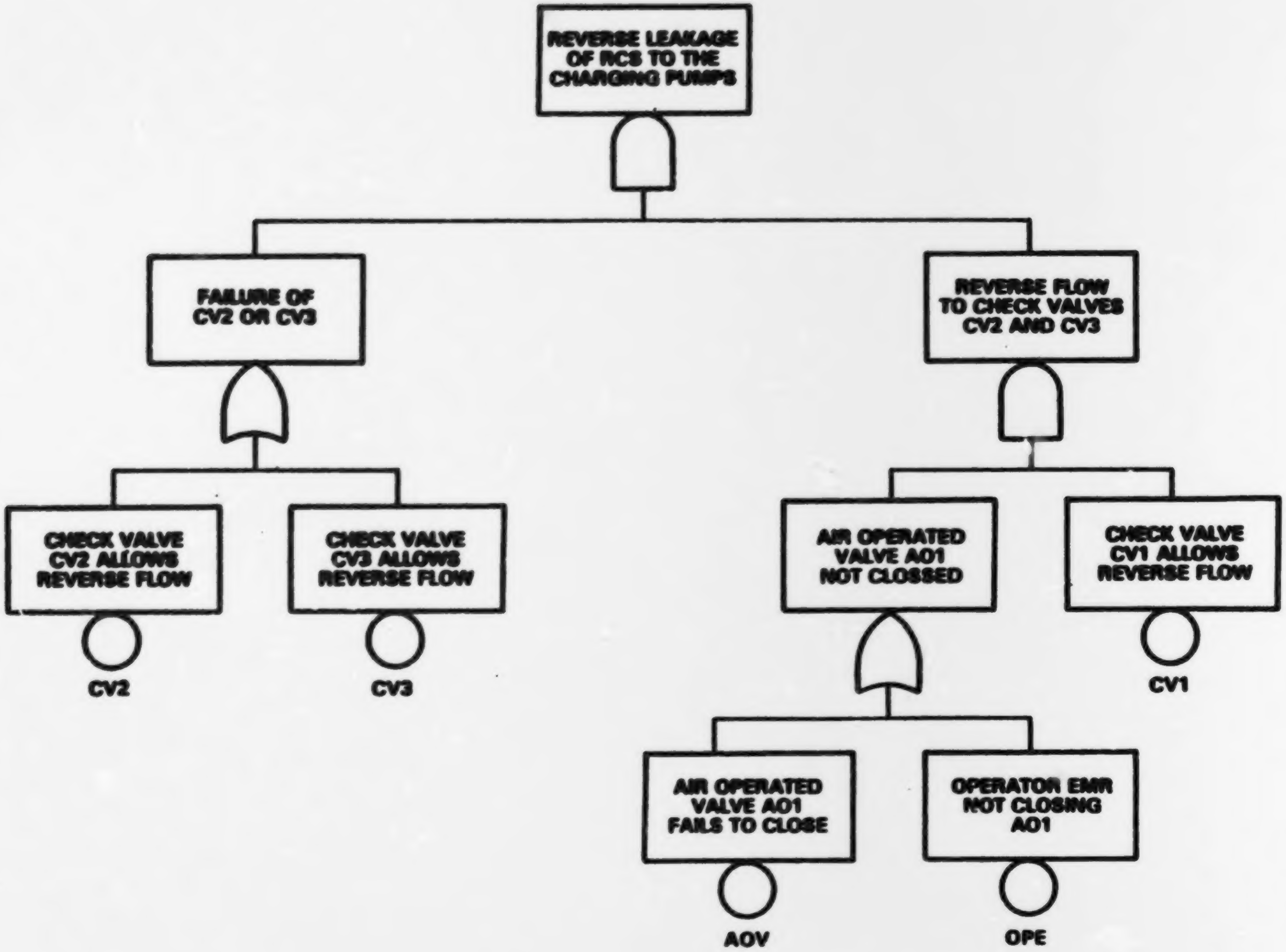
REVERSE LEAKAGE OF RCS TO THE CHARGING PUMPS
FAILURE OF CV2 OR CV3
REVERSE FLOW TO CHECK VALVES CV2 AND CV3
CHECK VALVE CV2 ALLOWS REVERSE FLOW
CHECK VALVE CV3 ALLOWS REVERSE FLOW
AIR OPERATED VALVE AO1 NOT CLOSSED
CHECK VALVE CV1 ALLOWS REVERSE FLOW
CV2
CV3
CV1
AIR OPERATED VALVE AO1 FAILS TO CLOSE
OPERATOR EMR NOT CLOSING AO1
AOV
OPE

Figure V-11.A-2. FAULT TREE FOR THE EVENT "REVERSE LEAKAGE OF RCS TO THE CHARGING PUMPS"

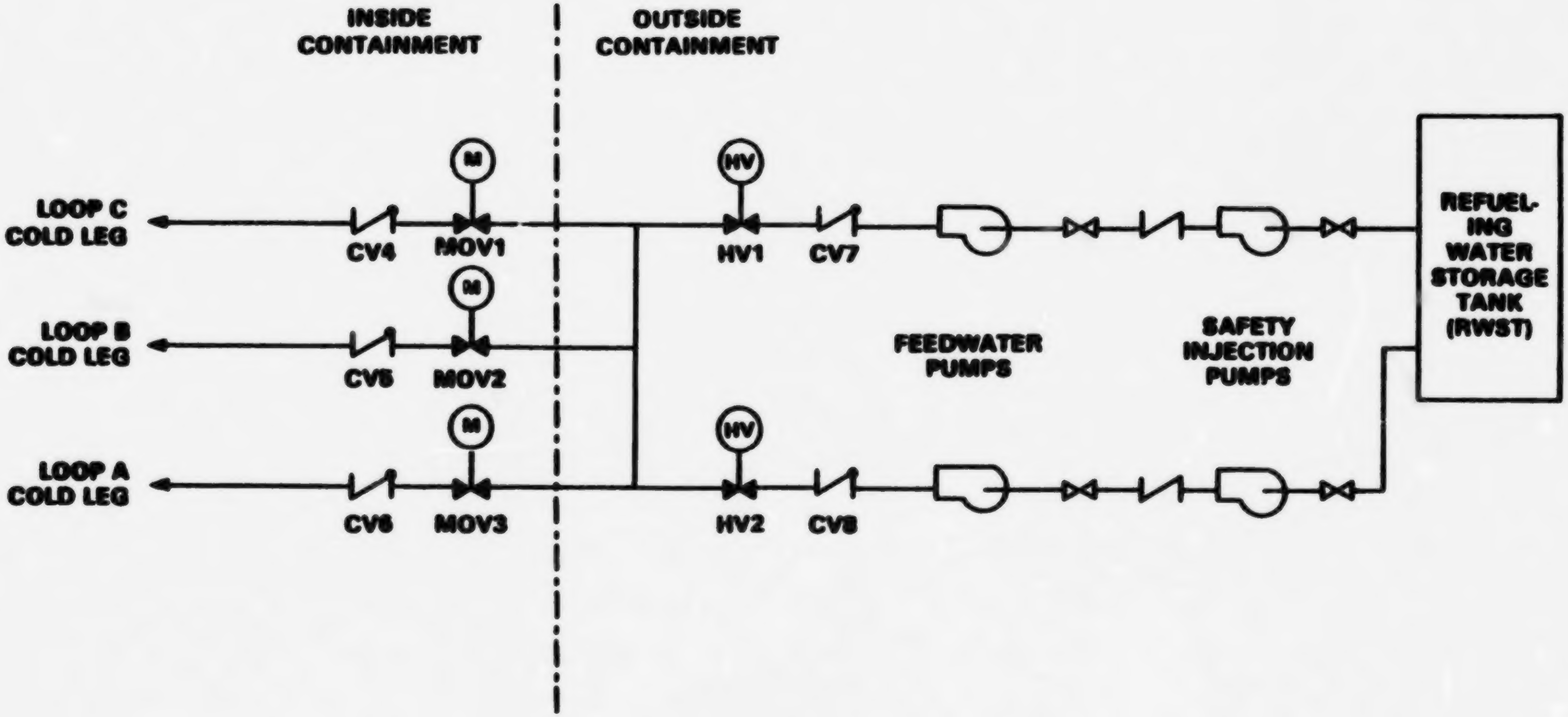
INSIDE CONTAINMENT
OUTSIDE CONTAINMENT
LOOP C COLD LEG
LOOP B COLD LEG
LOOP A COLD LEG
M
CV4
MOV1
CV5
MOV2
CV6
MOV3
HV
HV1
CV7
HV2
CV8
FEEDWATER PUMPS
SAFETY INJECTION PUMPS
REFUELING WATER STORAGE TANK (RWST)

Figure V-11.A-3. SIMPLIFIED SCHEMATIC OF THE SAFETY INJECTION SYSTEM

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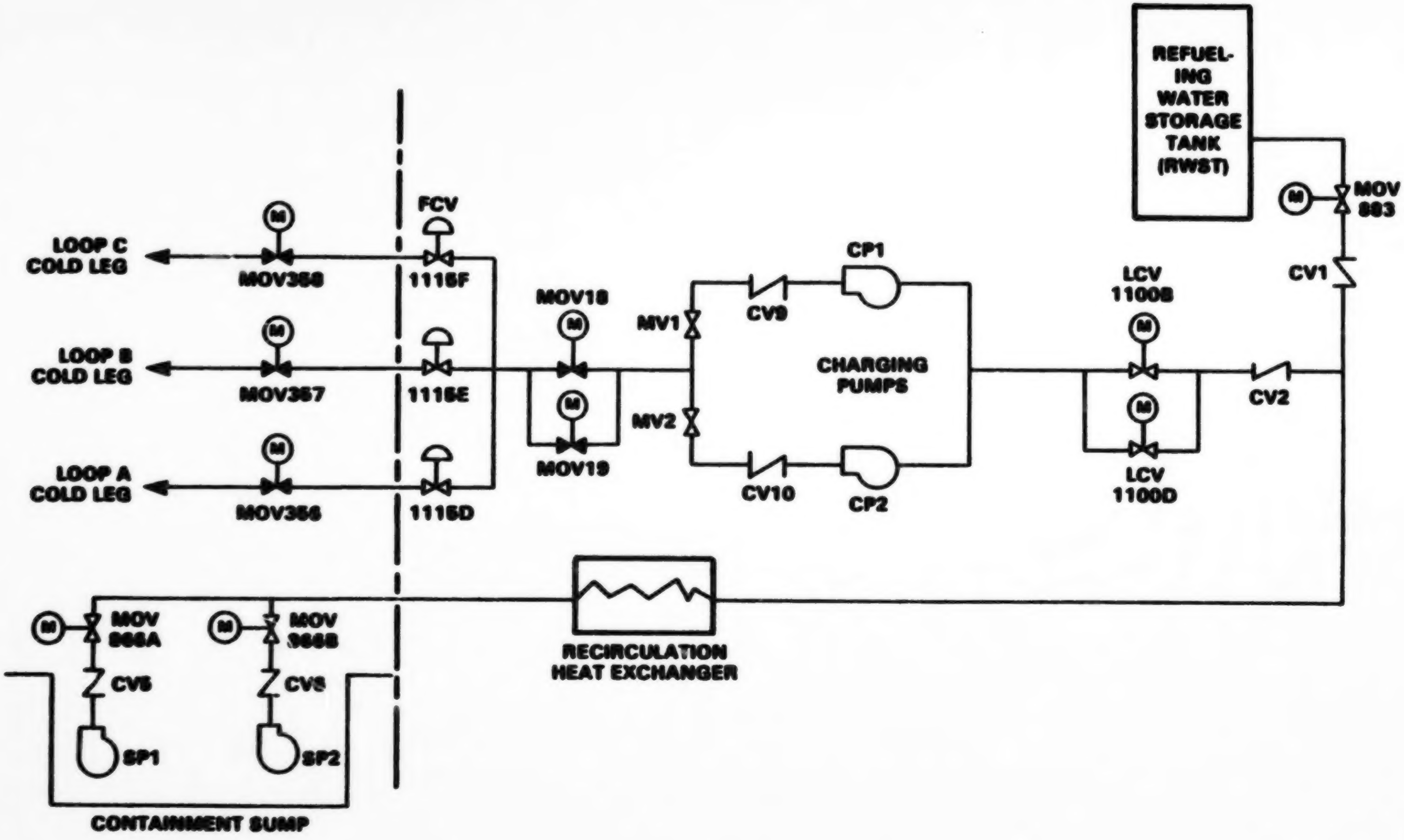
REFUELING WATER STORAGE TANK (RWST)
M
MOV 883
CV1
LOOP C COLD LEG
LOOP B COLD LEG
LOOP A COLD LEG
M
MOV358
MOV357
MOV356
FCV
1115F
1115E
1115D
MOV18
MOV19
MV1
MV2
CV9
CV10
CP1
CP2
CHARGING PUMPS
LCV 1100B
LCV 1100D
CV2
MOV 866A
MOV 866B
CV5
CV6
SP1
SP2
RECIRCULATION HEAT EXCHANGER
CONTAINMENT SUMP

Figure V-11.A-4. SIMPLIFIED SCHEMATIC OF THE LONG TERM CORE COOLING SYSTEM

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Table V-11.A-1 Failure Rates for Various Faults Shown on Figure V-11.A-2

Fault Identifier	Failure Mode	Failure Rate	Fault Duration	Unavailability	Comments
CV1, CV4, CV5, CV6	Check Valve Reverse	3.0×10^{-7}/Hr	6570 Hrs	1.9×10^{-3}	Checked every refueling
CV2, CV3, CV7, CV8, CV9, CV10	Leakage	3.0×10^{-7}/Hr	15 Years	3.9×10^{-2}	Never checked for reverse flow
AOV	Air operated valve fails to close	8.3×10^{-7}/Hr	6570 Hrs	5.4×10^{-3}	Checked every refueling
OPE	Operator error to close AOV	-	-	1.0×10^{-3}	NUREG/CR 1278, Table 10-2
HE, HE1, HE2	Human error Close MOVs after test			3.0×10^{-3}	NUREG/CR 1278, Table 20-20

V-11.B RHR Interlock Requirements

1. NRC Evaluation

The current design of the Residual Heat Removal System (RHRS) at San Onofre includes two motor operated valves (MOVs) on the suction and two on the discharge side to isolate the RHRS from the main coolant system. The two MOVs closest to the reactor coolant system (RCS) have pressure interlocks to prevent them from opening if the RCS pressure is above RHRS design pressure. However, both valves use the same pressure sensor. The other MOVs do not have any pressure interlocks. This configuration does not comply with the NRC's requirement of diverse and independent pressure interlocks for isolation of the RHRS and main coolant system.

2. NRC Recommendation

No modifications to the RHRS interlock mechanism are recommended until the low temperature overpressurization protection review (USI-A-26) is completed.

3. Systems Affected

Only the residual heat removal (RHR) system is affected by this issue.

4. Comments

None

5. Analysis

The scenario of most concern is the cooldown from hot shutdown to cold shutdown and initiation of residual heat removal system operation. If the MOVs connecting the main coolant system and RHRS are opened at a pressure which is considerably higher than the design pressure of the RHRS, possibility of damage to the RHRS piping and components and initiation of a LOCA would exist. The first event in the sequence of events that could lead to the above scenario for LOCA is an error by the shift supervisor in opening the MOVs much above the design pressure of the RHRS. Based on

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Handbook of Human Reliability (NUREG/CR 1278) an error of commission similar to this action has a probability of 3.0×10^{-3}. After initiation of the accident there are several indicators in the control room to help the operator realize a LOCA has occurred. At this point his corrective actions would include isolation of the MOVs if possible and initiation of the low pressure injection system to make up for any lost fluid. Since the reactor is shutdown and only decay heat is being removed there is a reasonable amount of time, on the order of 30 minutes or so, for the operator to recover his error before any substantial core damage would occur. In the Interim Reliability Evaluation Program (IREP), the failure of the operator to recover from an error resulting in an accident when he has in the order of 30 minutes to one hour was estimated to be 3×10^{-2}.

Based on WASH-1400 data, the frequency of failure of pressure sensors is 2.7×10^{-7} per hour. Assuming an annual refueling and consequently annual testing of the pressure sensor, the pressure sensor unavailability is calculated from the relationship $\lambda T/2$. In this relationship λ is the failure rate of the component and T is the time between tests. Based on this, the unavailability of the pressure sensor is 1.4×10^{-3}. Thus failure of the RHRS isolation in this case becomes the probability of an error of commission (3×10^{-3}) times the unavailability of the pressure sensor (1.4×10^{-3}) leading to a LOCA frequency of 4.2×10^{-6}/yr. The core melt frequency in this case would be equal to $(4.2 \times 10^{-6}) \times (3 \times 10^{-2}) = 1.2 \times 10^{-7}$/yr. An alternative is to use two independent pressure sensors, one for the upstream RHR's MOVs and one for the downstream RHR's MOVs. This entirely eliminates the human action. The failure of the RHRS isolation in this case becomes the algebraic product of the unavailabilities (1.4×10^{-3}) of the pressure sensors leading to a LOCA frequency of 1.9×10^{-6}/yr. The core melt fequency in this case would be equal to $(1.9 \times 10^{-6}) \times (3 \times 10^{-2}) = 5.7 \times 10^{-8}$/yr. Since no PRA has been performed for San Onofre, the exact core melt probability of this plant is not known. Probabilistic risk assessments performed on similar PWRs in the IREP, RSSMAP and WASH-1400 have shown that the core melt frequency for a typical PWR ranges from 3×10^{-5} to 2×10^{-4}. Thus, the contribution of the core melt frequency of 1.2×10^{-7} to these values is judged to be very small.

6. Conclusion

The current procedure for initiating of the residual heat removal system, consisting of opening of two MOV's with preventive pressure sensors from control room and two other MOVs with administrative control results in the possibility of core melt on the order of 1.2×10^{-7}/yr. The independent diverse pressure interlocks mechanism reduces this possibility of core melt to 5.7×10^{-8}/yr. Since the contribution of these frequencies to the overall core melt frequency is judged to be small, no changes in the RHR interlock system seem to be necessary. Thus, we rank the risk significance of this issue as low.

VI-4 Containment Isolation System

1. NRC Evaluation

Many of the San Onofre containment penetrations currently do not meet NRC's current General Design Criteria. Table VI-4-1 lists these penetrations and their areas of non-compliance.

2. NRC Recommendation

Change penetration configurations to meet the General Design Criteria (GDC).

3. Systems Affected

The ability of the containment penetrations to isolate and insure containment integrity is affected by the configurations of the penetrations.

4. Comments

The containment penetrations were analyzed, those found not in compliance categorized depending on the particular configuration of the penetration. The unavailabilities of the containment penetrations were calculated using the available information which did not include any details on the isolation valves. Therefore, the results presented are not intended as a definitive analysis, but instead,are meant for comparison purposes only.

5. Analysis

There are five cases where the particular configuration of the containment penetration does not conform to the General Design Criteria. The five cases are characteristic of penetrations which have an identical configuration and therefore are treated collectively. In the first case two penetrations are described, while others are characteristic of from one to two penetrations each.

Each penetration case is drawn in both the "before" and "after" configurations in regard to their meeting the GDC. As mentioned previously, detailed information on the valves used for containment isolation was not available; therefore, the analysis does not consider either control or motive power or isolation signals received by the valves. Valves outside containment are assumed to be checked monthly, resulting in a fault exposure time for most events of 360 hours. Those components inside containment are assumed to be checked yearly and therefore are given a fault exposure time of 4,380 hours.

Only those penetrations four inches or larger in diameter are considered significant in terms of possible containment leakage (see WASH-1400, Appendix II, Section 5.12).

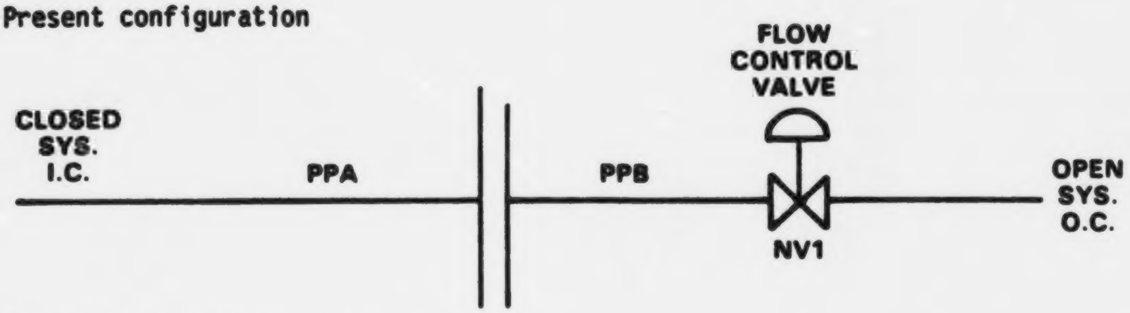
6. Conclusions

The results of the analysis of the current and NRC recommended configurations for various containment penetrations show that the failure probability of the existing configuration is very low. Typically the failure probability of containment isolation is in the order of 10^{-3} (WASH-1400). The modest changes shown in this analysis have a very small effect on the failure probability of the containment isolation. Thus, no changes in the containment isolation configuration seem to be necessary. From the risk point of view this issue is ranked low.

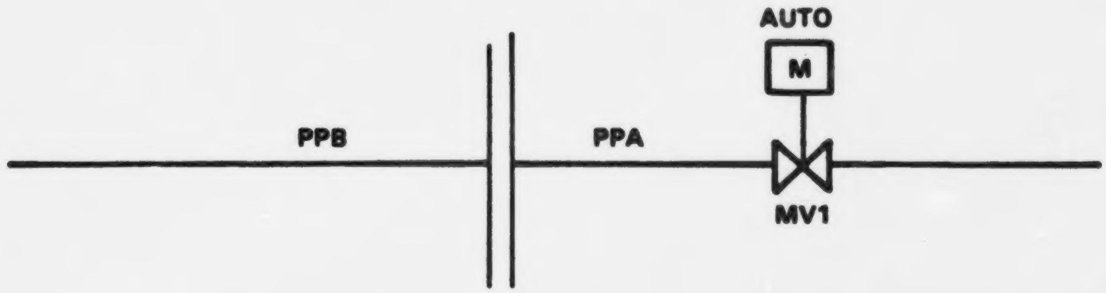
Case I:

Applies to penetration #A-1A, A-1C

Present configuration


FLOW CONTROL VALVE
CLOSED SYS. I.C.
PPA
PPB
OPEN SYS. O.C.
NV1

GDC Required Configuration


AUTO
M
PPB
PPA
MV1

The boolean equations which describe these configurations are as follows:

Before: PPA * (PPB + NV1)

After: PPA * (PPB + MV1)

Using the failure rates presented in Table VI-4-3, the following unavailabilities were calculated.

Case 1 before: 4.4E-7 * (3.6E-8 + 1E-1) = 4.4E-8

Case 1 after: 4.4E-7 * (3.6E-8 + 1E-3) = 4.4E-10

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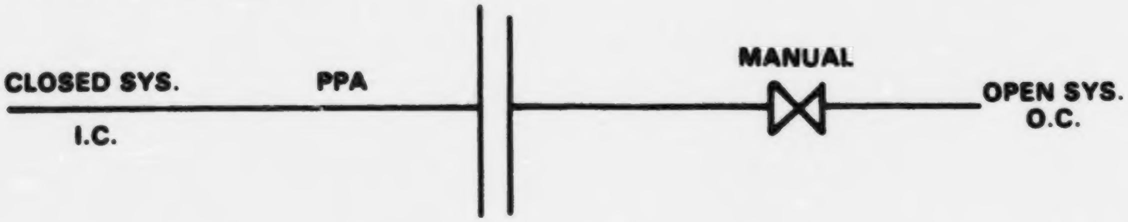
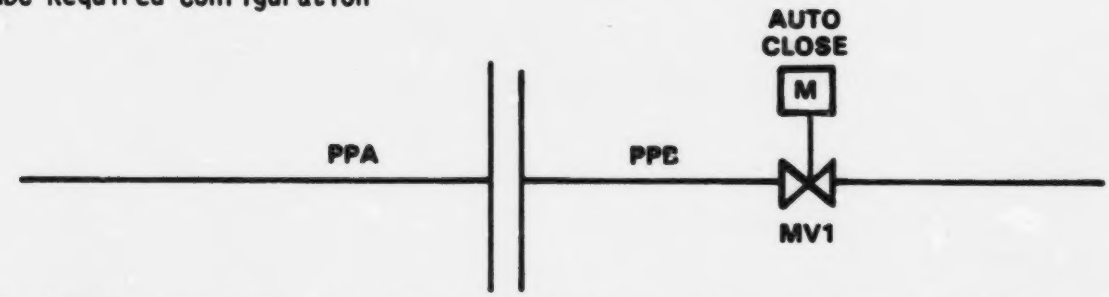
Case II:
Applies to penetration #A-1B, A-1D

Present Configuration


CLOSED SYS.
I.C.
PPA
MANUAL
OPEN SYS.
O.C.

GDC Required Configuration


AUTO
CLOSE
M
PPA
PPB
MV1

The boolean equations which describe these configurations are as follows:

Before: PPA

After: PPA * (PPB + MV1)

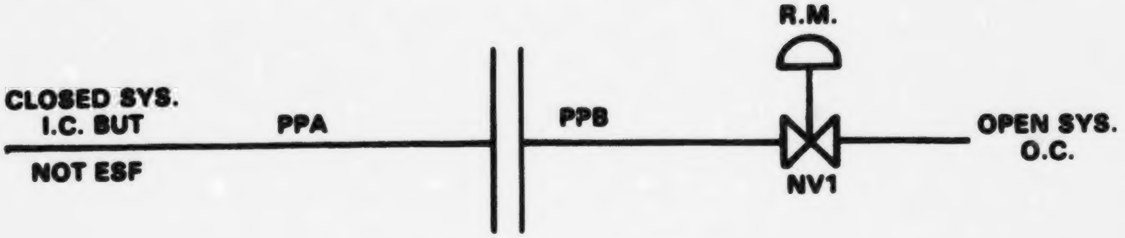
Using the failure rates presented in Table VI-4-3, the following unavailabilities were calculated.

Case II before: 4.4E-7

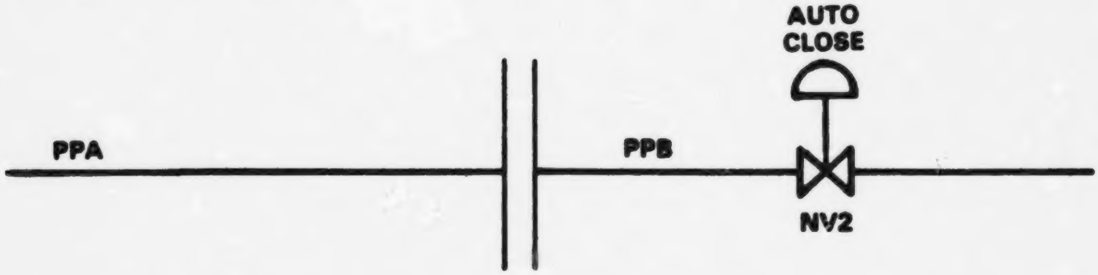
Case II after: 4.4E-7 * (3.6E-8 + 1E-3) = 4.4E-10

Case III
Applies to penetration #A-9A

resent configuration:


R.M.
CLOSED SYS.
I.C. BUT
NOT ESF
PPA
PPB
OPEN SYS.
O.C.
NV1

GDC required configuration


AUTO
CLOSE
PPA
PPB
NV2

The boolean equations which describe these configurations are as follows:

Before: PPA * (PPB + NV1)

After: PPA * (PPB + NV2)

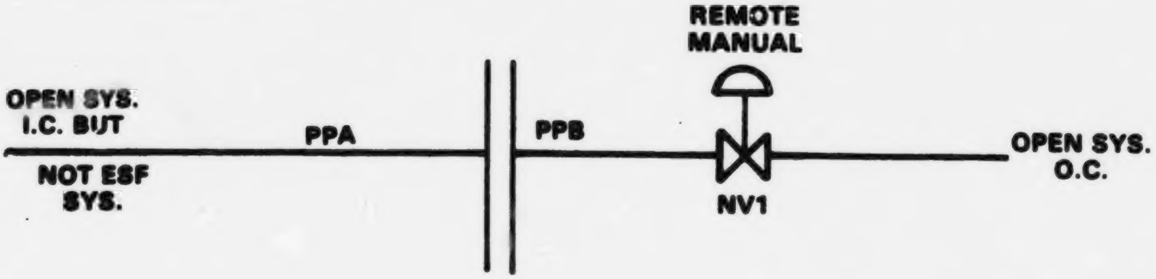
Using the failure rates presented in Table VI-4-3, the following unavailabilities were calculated.

Case III before: 4.4E-7 * (3.6E-8 + 1E-1) = 4.4E-8

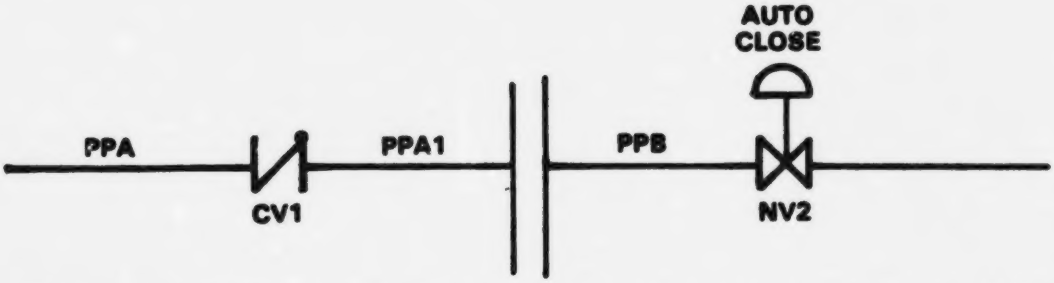
Case III after: 4.4E-7 * (3.6E-8 + 3E-4) = 1.3E-10

Case IV
Applies to penetrations #A-9B, A-14

Present configuration:


REMOTE MANUAL
OPEN SYS. I.C. BUT
NOT ESF SYS.
PPA
PPB
NV1
OPEN SYS. O.C.

GDC required configuration:


AUTO CLOSE
PPA
PPA1
PPB
CV1
NV2

The boolean equations which describe these configurations are as follows:

Before: PPA * (PPB + NV1)

After: PPA * (MV1 + PPA) * (PPB + NV2)

Using the failure rates preented in Table VI-4-3, the following unavailabilities were calculated.

Case IV before: 4.4E-7 * (3.6E-8 + 1E-1) = 4.4E-8

Case IV after: 4.4E-7 * (1E-3 + 4.4E-7) * (3.6E-8 + 3E-4) = 1.3E-13

Case V
Applies to penetration #B-18A

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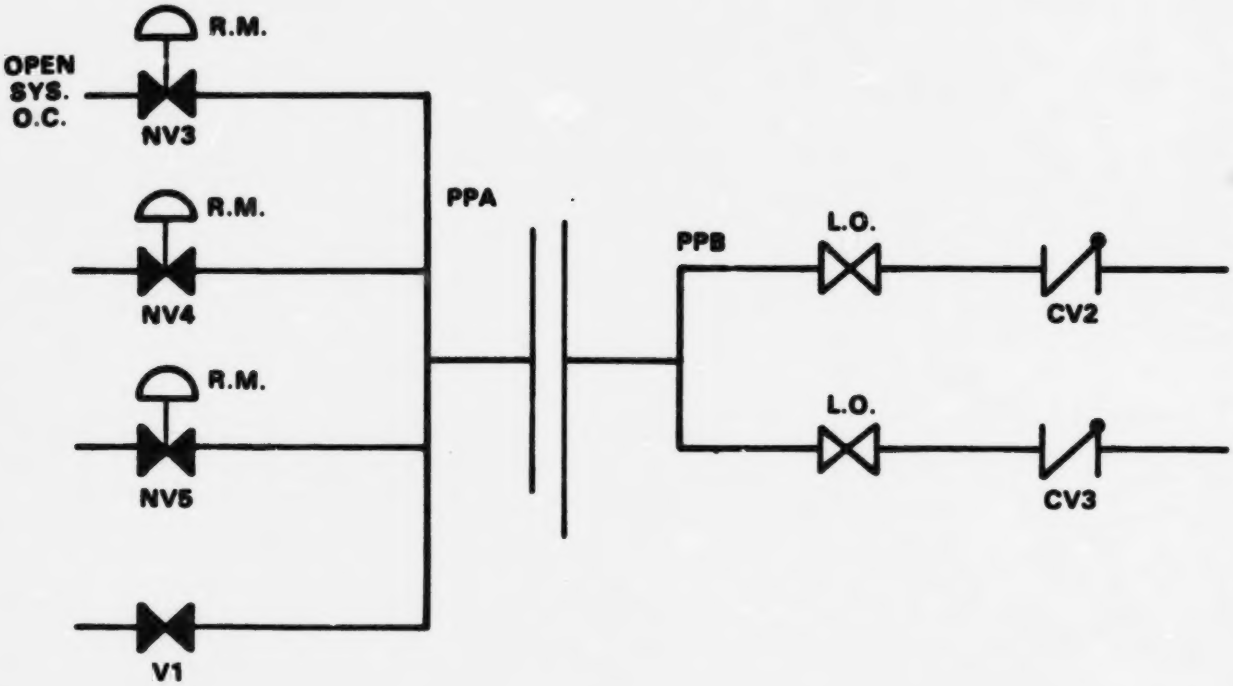
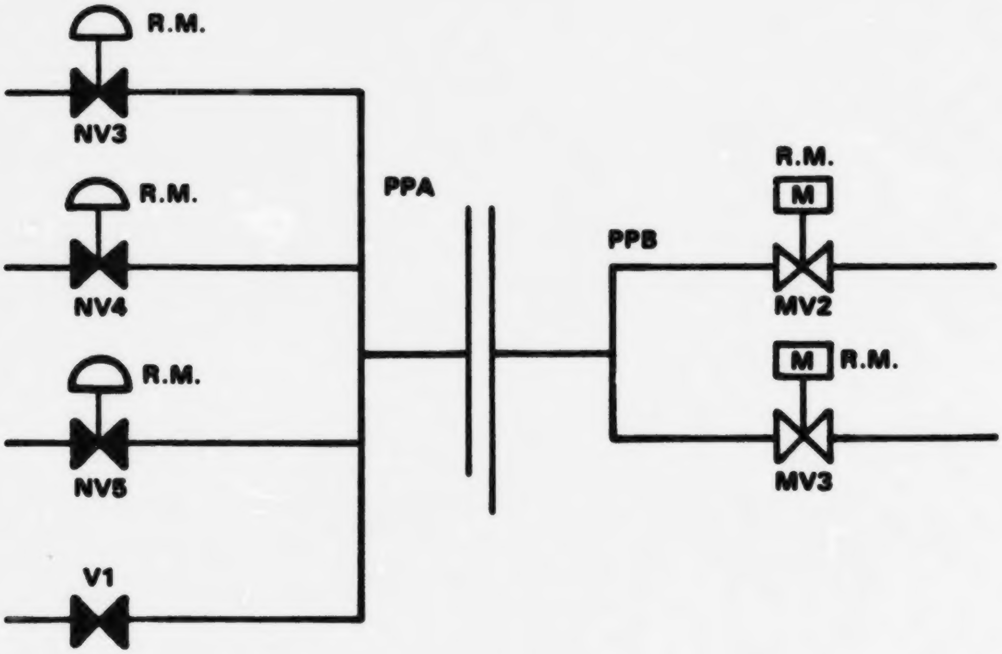
Present configuration:


R.M.
OPEN
SYS.
O.C.
NV3
R.M.
NV4
R.M.
NV5
V1
PPA
PPB
L.O.
CV2
L.O.
CV3

GDC required configuration:


R.M.
NV3
R.M.
NV4
R.M.
NV5
V1
PPA
PPB
R.M.
M
MV2
M
R.M.
MV3

The boolean equations which describe these configurations are as follows:

Before: $(NV3 + NV4 + NV5 + V1 + PPA) * (PPB + CV2 + CV3)$

After: $(NV3 + NV4 + NV5 + V1 + PPA) * (PPB + MV2 + MV3)$

Using the failure rates presented in Table VI-4-3, the following unavailabilities were calculated.

Case V before: $(1E{-}2 + 1E{-}2 + 1E{-}2 + 1E{-}2 + 4.4E{-}7) *$
$(3.6E{-}8 + 1.1E{-}4 + 1.1E{-}4) = 8.8E{-}6$

Case V after: $(1E{-}2 + 1E{-}2 + 1E{-}2 + 1E{-}2 + 4.4E{-}7) *$
$(3.6E{-}8 + 1E{-}1 + 1E{-}1) = 8E{-}3$

TABLE VI-4-1

Penetration #	Deficiency
A-1A	A
A-1C	A
A-1B	A
A-1D	A
A-9A	A,B
A-9B	A,B
A-14	A,B
B-18A	A

NOTES:

A. Valve type: deviates by not having an automatic isolation valve outside containment.

B. Valve number: deviates by not having an isolation valve inside containment.

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TABLE VI-4-2

Penetration #	Unavailability	
	Present Configuration	GDC Required
A-1A	4.4E-8	4.4E-10
A-1C	4.4E-8	4.4E-10
A-1B	4.4E-7	4.4E-10
A-1D	4.4E-7	4.4E-10
A-9A	4.4E-8	3E-7
A-9B	4.4E-8	3E-7
A-14	4.4E-8	3E-7
B-18A	8.8E-6	8E-3

TABLE VI-4-3
FAULT SUMMARY

Event Name	Sub Event Description	Failure Rate	Fault Exposure Time	Sub Event Unavailability	Total Unavailability
PPA (I.C.)	Pipe Rupture	1E-10/hr	4.4E+3 hrs	4.4E-7	4.4E-7
PPB (O.C.)	Pipe Rupture	1E-10/hr	360 hrs	3.6E-8	3.6E-8
MV1 (AOV,NOFO, manual close)	Rupture	1E-8/hr	360 hrs	3.6E-6	
	Fails to operate	3E-4/demand		3E-4	
	Operator fails to act	1E-1/demand		1E-1	1E-1
MV1 (MOV, NOFO auto close)	Rupture	1E-8/hr	360 hrs	3.6E-6	
	Fails to close	1E-3/demand		1E-3	1E-3
CV1 (check valve)	Internal leakage	3E-7/hr	4.4E+3 hrs	1.3E-3	
	Rupture	1E-8/hr	4.4E+3 hrs	4.4E-5	1.3E-3
MV2 (AOV,NOFO, auto close)	Rupture	1E-8/hr	360 hrs	3.6E-6	
	Fails to operate	3E-4/demand		3E-4	3E-4
MV3,MV4,MV5 (AOV,NCFO, manual)	Rupture	1E-8/hr	4.4E+3 hrs	4.4E-5	
	Fail to restore after T or M	1E-2		1E-2	1E-2
V1 (manual valve NCFO)	Rupture	1E-8/hr	4.4E+3 hrs	4.4E-5	
	Fail to restore after T or M	1E-2		1E-2	1E-2
CV2,CV3 (check valve)	Internal leakage	3E-7/hr	360 hrs	1.1E-4	
	Rupture	1E-8/hr	360 hrs	3.6/E-6	1.1E-4
MV2,MV3 (MOV,NOFO, manual close)	Rupture	1E-8/hr	360 hrs	3.6E-6	
	Fails to operate	1E-3/demand		1E-3	
	Operator fails to act	1E-1/demand		1E-1	1E-1

NOTES:

Demand probabilities are based on presence of proper input control signals.

Auto isolation valves are assumed to move to position of greater safety on loss of power.

Fault exposure time assumes monthly checking of components outside containment and yearly checking for those components inside containment.

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VI-7.B ESF Switchover From Injection To Recirculation

1. NRC Evaluation

The current procedure for switchover from injection mode to recirculation mode at San Onofre Nuclear Power Plant consists of manual switchover of the pumps from the injection source, namely the Refueling Water Storage Tank (RWST) to the recirculation source, namely the containment sump. Current NRC guideline indicates that automatic switchover is preferable to manual switchover. But in case of manual switchover, the guideline indicates that there should be sufficient time (20 minutes) available to the operator to perform the switchover tasks. Currently the operator is instructed to initiate the switchover from injection to recirculation when the RWST level has dropped to 12% (32,472 gallons). This switchover action must be completed before the RWST level drops to below 7% (18,644 gallons) so that no damage to the pumps would occur. The time between 12% and 7% RWST level which is essentially the time available to the operator for switchover is between 5.8 to 10 minutes depending on the assumed flow rates. Additionally, there is only one pneumatic level indicator that would provide information on the RWST water level. A second level switch also exists which only initiates an alarm once the RWST level has dropped to 21%. Thus, given the lack of redundancy in level indication and shorter than recommended period time for manual switchover to recirculation, there is a possibility of failure to perform the switchover tasks before the RWST water level has dropped so low that pump damage might occur.

2. NRC Recommendation

Because the time available to the operator to perform the manual switchover tasks is shorter than the guidelines' recommended time, addition of an automatic mechanism for the switchover from injection to recirculation was recommended.

3. Systems Affected

The Emergency Core Cooling Recirculation System, including the charging pumps which are part of the long term recirculation system, is the system affected by this issue.

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4. Comments

None

5. Analysis

The main concern in this issue is related to a scenario where a large break LOCA has occurred and the safety injection, feedwater, refueling water and charging pumps have started to deliver water from RWST to the core. The combined maximum flow rate of these pumps is 22,405 gpm. Based on a RWST volume of 241,172, it takes about 8 minutes to reach the RWST low-level which is at 21% of the RWST volume. At this point an alarm will sound and the safety injection pumps and feedwater pumps are tripped by the operator and charging pumps are realigned to pump water through safety injection lines. Figure VI-7.B.1 shows the simplified schematic of the Emergency Core Cooling Injection system. Figure VI-7.B.2 shows the simplified schematic of the Emergency Core Cooling Injection at reduced flow and Emergency Core Cooling Recirculation. Note that at reduced flow the charging and refueling pumps continue to draw water from RWST. Once the RWST level drops to 12% the operator is instructed to initiate recirculation flow to the core from the sump. Depending on the flow rate it takes anywhere between 6 minutes to 10 minutes until the RWST level has dropped to 7%, below which possible damage to the pumps might occur. During this whole period there is only one level indicator that would provide information to the operator on when the switchover should be initiated.

A fault tree for the event "Failure of the Emergency Core Cooling Recirculation system" was developed and is shown in Figure VI-7.B-3. The contribution of various faults to the top event in this fault tree can be divided into faults under "Failure to Switchover to Recirculation Mode" (see Sheet 1 of the fault tree) OR "Other Faults" such as mechanical, electrical or other failures that reult in failure of the system to deliver sufficient water to the core. To quantify this tree, failure rates for various faults shown on the fault tree were calculated and are shown in Table VI-7.B-1. The data in this table are from WASH-1400 and IEE-Std-500. The "Top Event" (TE) can be written as

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TE = (Failure to Switchover to Recirculation Mode) +
(Other Faults)

The failure to switchover to recirculation mode can further be broken down as is shown in the fault tree:

TE = [Operator Error in Reading the Level Indicator (OPE1)] +
[Operator Error in Performing Switchover Tasks (OPE2)] +
[Failure of the RWST Level Indicator (LI)] +
(Other Faults)

After quantifying the fault tree the results are:

$$TE = OPE1 + OPE2 + 2.2\times10^{-2} + 1.2\times10^{-4}$$

The operator error of commission in reading a recorder (OPE1) is 1.0×10^{-4} based on existence of an annunciator (NUREG/CR-1278). The operator error of omission when using a written procedure (OPE2) with a long list (greater than 10) of tasks is 3.0×10^{-3} (NUREG/CR-1278). Thus the total probability of failure of the recirculation system is 2.5×10^{-2}. Note that the single failure of the water level indicator has the biggest contribution to this failure.

Now let us look at two alternatives. First a case where redundant, annunciated RWST level indicators are installed, i.e., a second level indicator is added to the present design of the system. In this case, because of the redundance in the water level indicators, the failure rate of level indicators reduces to 4.8×10^{-4}. This reduces the Top Event probability to 3.7×10^{-3}, which is a factor of 7 smaller than the original value.

The second case of interest is the automatic switchover. In this case it can be assumed that the probability of operator errors OPE1 and OPE2 would go to zero. Because of addition of the automatic switchover mechanism, there should be a contribution to the Top Event due to failure of this mechanism. Let us assume that this contribution is negligible. Based on these assumptions the lowest failure probability for the Top Event in this case would be 6.0×10^{-4}, which is a factor of 6 smaller than the case

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with redundant level indicators but manual switchover. It is important to note that an automatic switchover mechanism has a general drawback of possibility of an inadvertent switchover before there is sufficient water in the sump. This action could result in the possible pump cavitation and damage.

Let us now look at the frequency of core melt due to initiation of a large LOCA and failure of the recirculation system. The frequency of initiation of a large LOCA is 1.0×10^{-4}/year (WASH-1400). Thus, the core melt frequency based on initiation of a large LOCA and failure of the recirculation system is 2.5×10^{-6}/year for the current San Onofre design. This core melt frequency reduces to 3.7×10^{-7}/year for the case with redundant annunciated RWST level indicators but with manual switchover. The core melt frequency for the case of automatic switchover is further reduced to 6.0×10^{-8}/year. Since no probabilistic risk assessment has been performed for San Onofre, the exact core melt frequency of this plant is not known. But previous PRAs for similar PWRs in the IREP, RSSMAP and reactor safety study have shown that the overall core melt frequency is in the range of 3×10^{-5} to 2×10^{-4}. Thus, the core melt frequency due to failure of the switchover from injection to recirculation in the current San Onofre design would have a moderate contribution to the overall core melt frequency. The improvement in this frequency of a factor of 7 due to addition of redundant annunciated RWST water level indicators is sufficient to make the contribution of this event to the total core melt frequency fairly small. Obviously an automatic switchover mechanism reduces this core melt contribution even further.

6. Conclusions

The frequency of core melt due to a large LOCA and failure of the ECCS recirculation system in the current design of the San Onofre Nuclear Power Plant has a moderate effect on the overall core melt frequency. A factor of 7 decrease in this core melt frequency can be realized if a set of redundant annunciated RWST level indicators are installed. Further reduction in core melt frequency can be realized by installing an automatic switchover mechanism. The core melt frequency in the case where a set of redundant annunciated RWST level indicators have been installed is small enough that the change to an automatic switchover system does not seem to be necessary. The overall risk significance of this issue is ranked medium.

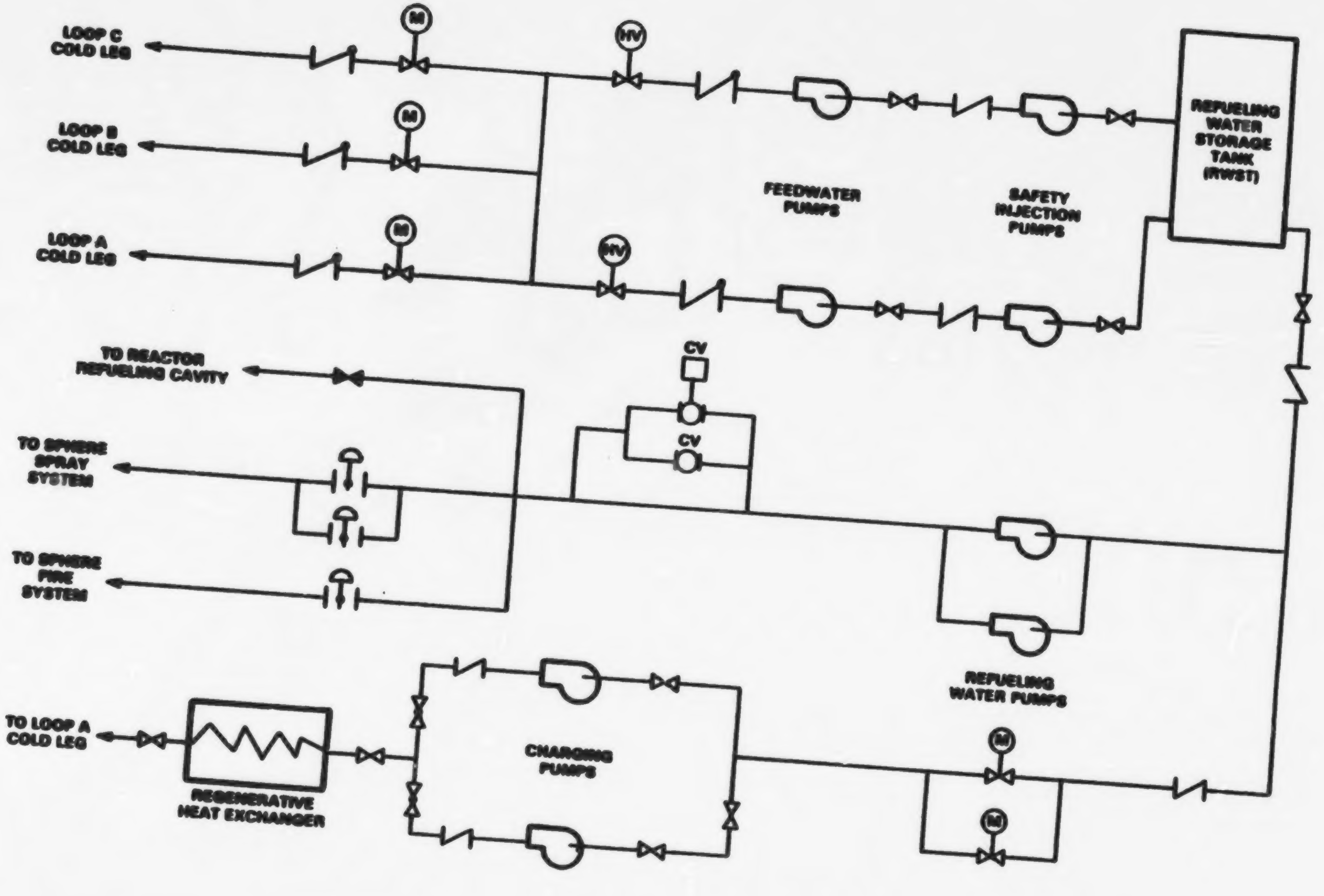
LOOP C COLD LEG
LOOP B COLD LEG
LOOP A COLD LEG
M
HV
FEEDWATER PUMPS
SAFETY INJECTION PUMPS
REFUELING WATER STORAGE TANK (RWST)
TO REACTOR REFUELING CAVITY
CV
TO SPHERE SPRAY SYSTEM
TO SPHERE FIRE SYSTEM
REFUELING WATER PUMPS
TO LOOP A COLD LEG
REGENERATIVE HEAT EXCHANGER
CHARGING PUMPS

Figure VI-7.B-1. SIMPLIFIED SCHEMATIC OF THE EMERGENCY CORE COOLING INJECTION SYSTEM

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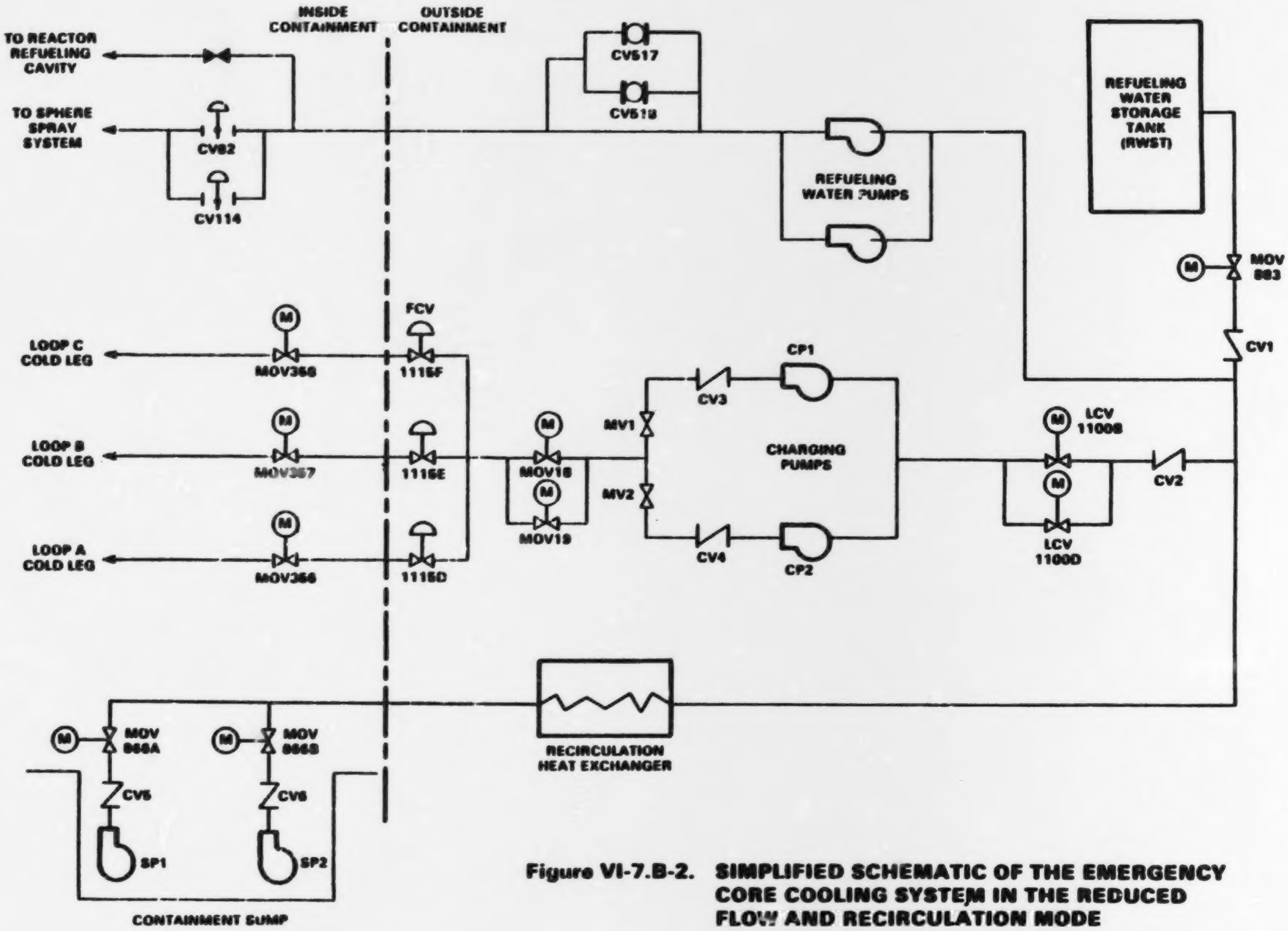

INSIDE CONTAINMENT
OUTSIDE CONTAINMENT
TO REACTOR REFUELING CAVITY
TO SPHERE SPRAY SYSTEM
CV82
CV114
CV517
CV518
REFUELING WATER PUMPS
REFUELING WATER STORAGE TANK (RWST)
M
MOV 883
CV1
LOOP C COLD LEG
LOOP B COLD LEG
LOOP A COLD LEG
MOV358
MOV357
MOV356
FCV
1115F
1115E
1115D
MOV18
MOV19
MV1
MV2
CV3
CV4
CP1
CP2
CHARGING PUMPS
LCV 1100B
LCV 1100D
CV2
RECIRCULATION HEAT EXCHANGER
MOV 866A
MOV 866B
CV5
CV6
SP1
SP2
CONTAINMENT SUMP

Figure VI-7.B-2. SIMPLIFIED SCHEMATIC OF THE EMERGENCY CORE COOLING SYSTEM IN THE REDUCED FLOW AND RECIRCULATION MODE

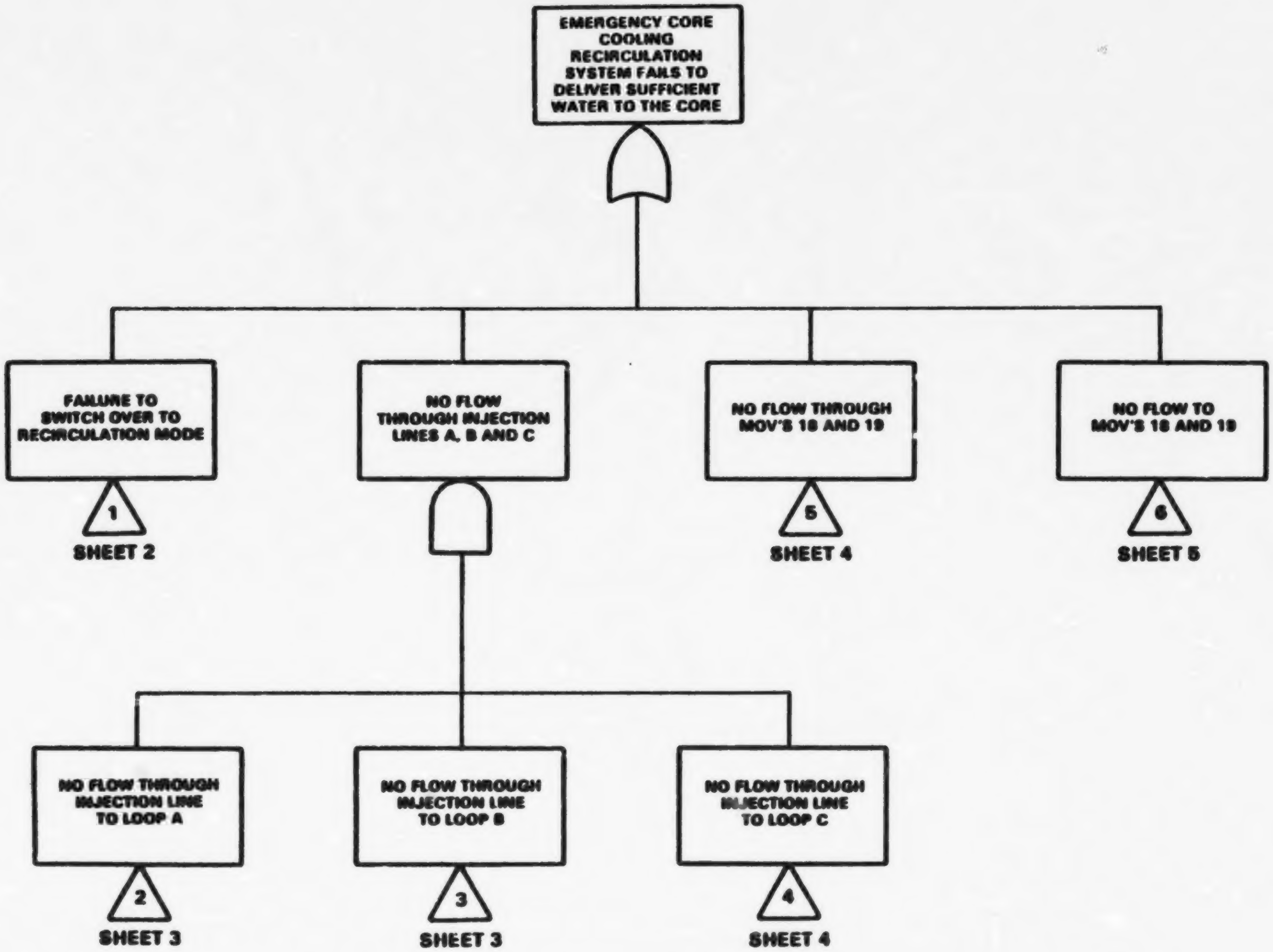

EMERGENCY CORE COOLING RECIRCULATION SYSTEM FAILS TO DELIVER SUFFICIENT WATER TO THE CORE
FAILURE TO SWITCH OVER TO RECIRCULATION MODE
1
SHEET 2
NO FLOW THROUGH INJECTION LINES A, B AND C
NO FLOW THROUGH MOV'S 18 AND 19
5
SHEET 4
NO FLOW TO MOV'S 18 AND 19
6
SHEET 5
NO FLOW THROUGH INJECTION LINE TO LOOP A
2
SHEET 3
NO FLOW THROUGH INJECTION LINE TO LOOP B
3
SHEET 3
NO FLOW THROUGH INJECTION LINE TO LOOP C
4
SHEET 4

Figure VI-7.B-3. FAULT TREE FOR THE EVENT "EMERGENCY CORE COOLING RECIRCULATION SYSTEM FAILS TO DELIVER SUFFICIENT WATER TO THE CORE" SHEET 1

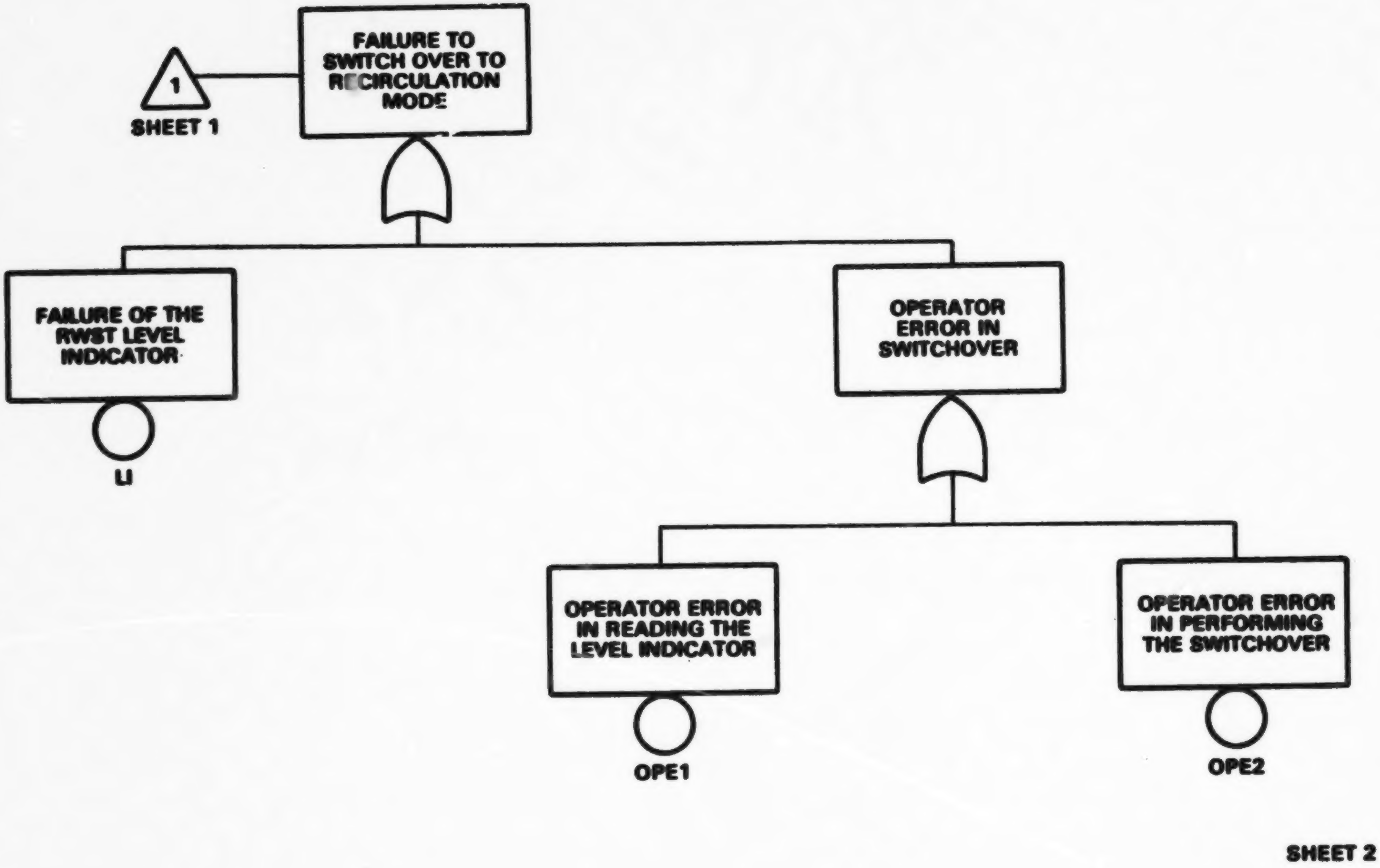

1
SHEET 1
FAILURE TO SWITCH OVER TO RECIRCULATION MODE
FAILURE OF THE RWST LEVEL INDICATOR
LI
OPERATOR ERROR IN SWITCHOVER
OPERATOR ERROR IN READING THE LEVEL INDICATOR
OPE1
OPERATOR ERROR IN PERFORMING THE SWITCHOVER
OPE2
SHEET 2

Figure VI-7.B-3. (CONTINUED)

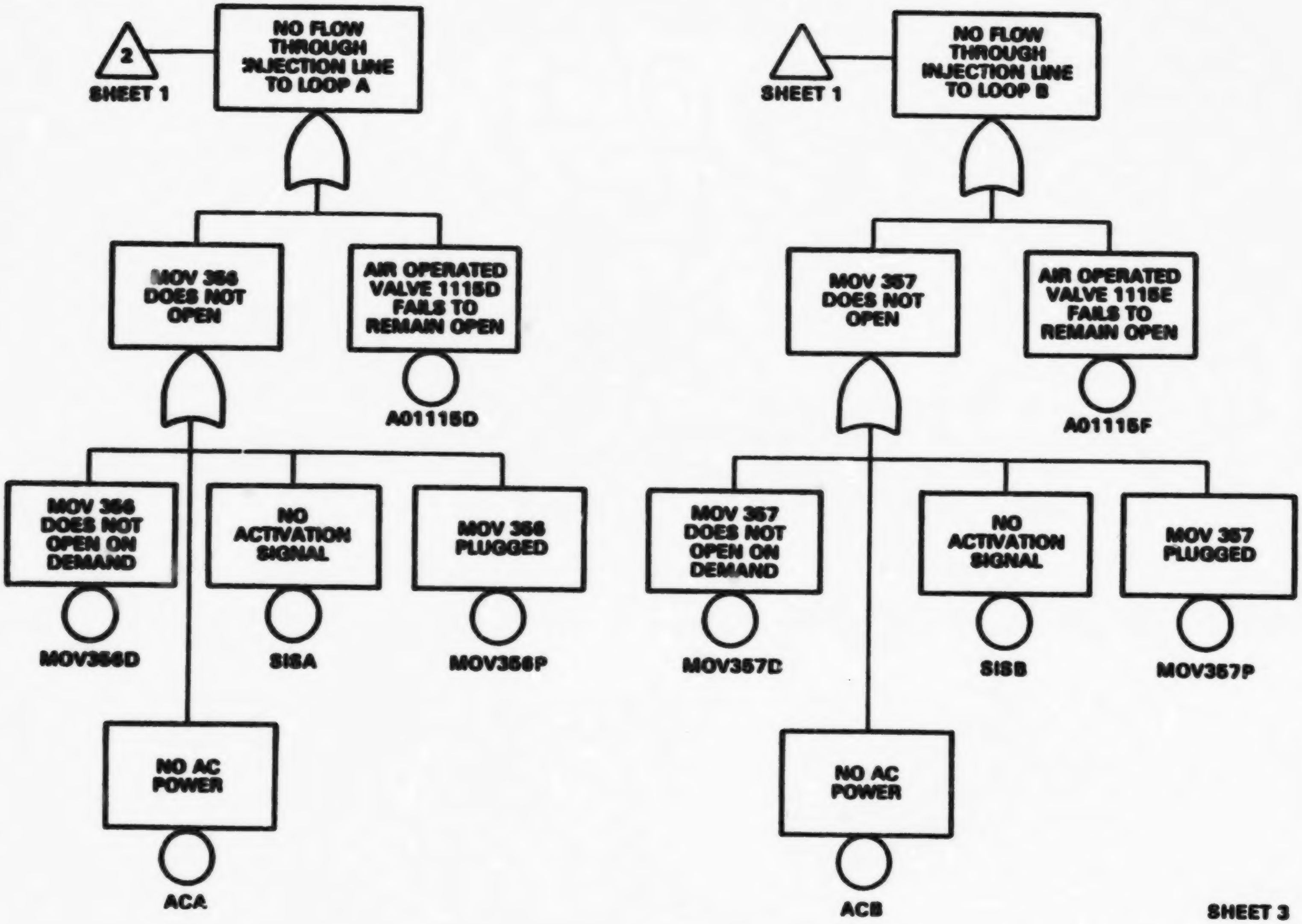

2
SHEET 1
NO FLOW THROUGH INJECTION LINE TO LOOP A
MOV 356 DOES NOT OPEN
AIR OPERATED VALVE 1115D FAILS TO REMAIN OPEN
A01115D
MOV 356 DOES NOT OPEN ON DEMAND
MOV356D
NO ACTIVATION SIGNAL
SISA
MOV 356 PLUGGED
MOV356P
NO AC POWER
ACA
SHEET 1
NO FLOW THROUGH INJECTION LINE TO LOOP B
MOV 357 DOES NOT OPEN
AIR OPERATED VALVE 1115E FAILS TO REMAIN OPEN
A01115F
MOV 357 DOES NOT OPEN ON DEMAND
MOV357D
NO ACTIVATION SIGNAL
SISB
MOV 357 PLUGGED
MOV357P
NO AC POWER
ACB
SHEET 3

Figure VI-7.B-3. (CONTINUED)

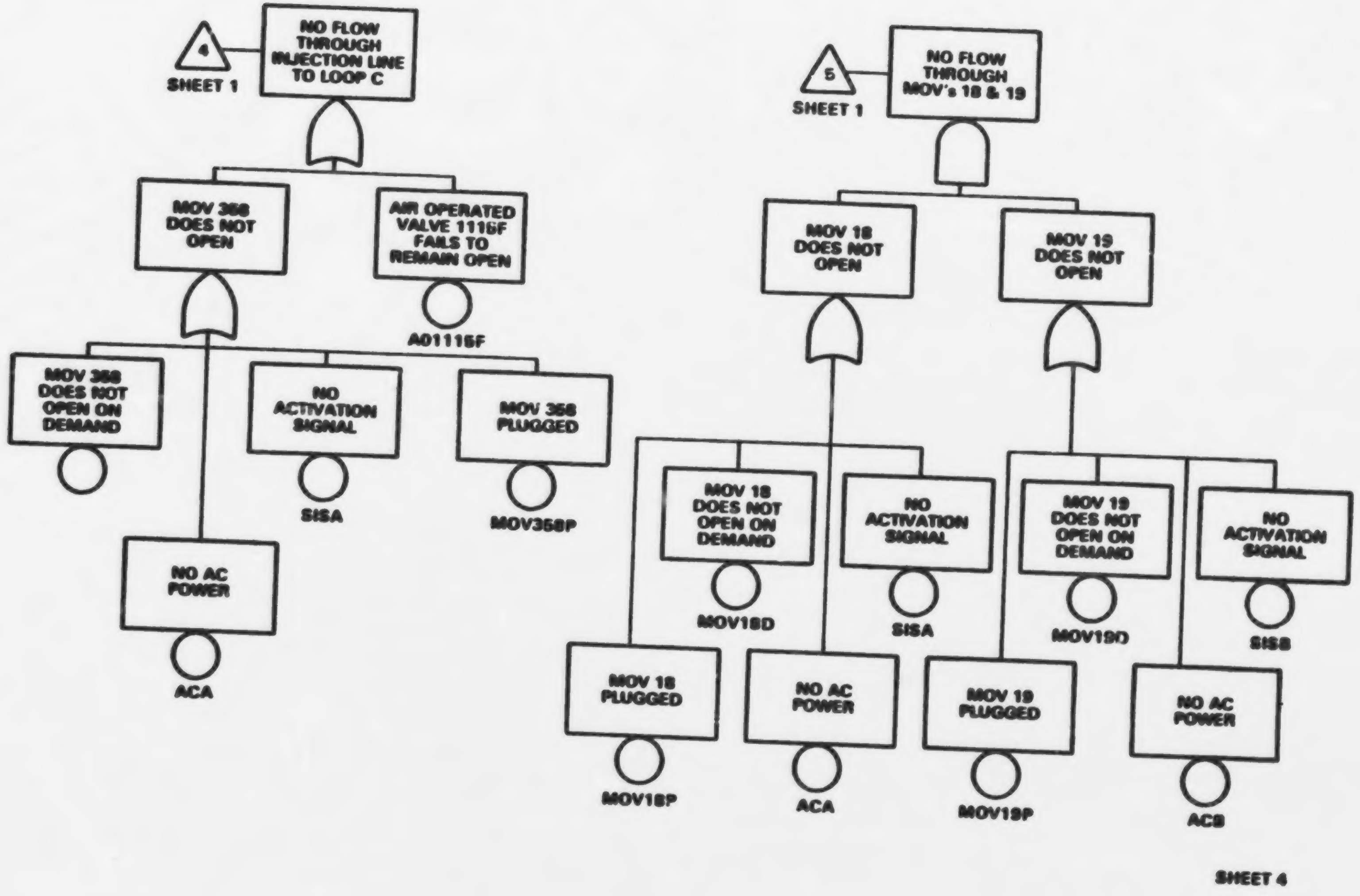

4
SHEET 1
NO FLOW THROUGH INJECTION LINE TO LOOP C
MOV 358 DOES NOT OPEN
AIR OPERATED VALVE 1115F FAILS TO REMAIN OPEN
A01115F
MOV 358 DOES NOT OPEN ON DEMAND
NO ACTIVATION SIGNAL
SISA
MOV 358 PLUGGED
MOV358P
NO AC POWER
ACA
5
SHEET 1
NO FLOW THROUGH MOV's 18 & 19
MOV 18 DOES NOT OPEN
MOV 19 DOES NOT OPEN
MOV 18 DOES NOT OPEN ON DEMAND
MOV18D
NO ACTIVATION SIGNAL
SISA
MOV 19 DOES NOT OPEN ON DEMAND
MOV19D
NO ACTIVATION SIGNAL
SISB
MOV 18 PLUGGED
MOV18P
NO AC POWER
ACA
MOV 19 PLUGGED
MOV19P
NO AC POWER
ACB
SHEET 4

Figure VI-7.B-3. (CONTINUED)

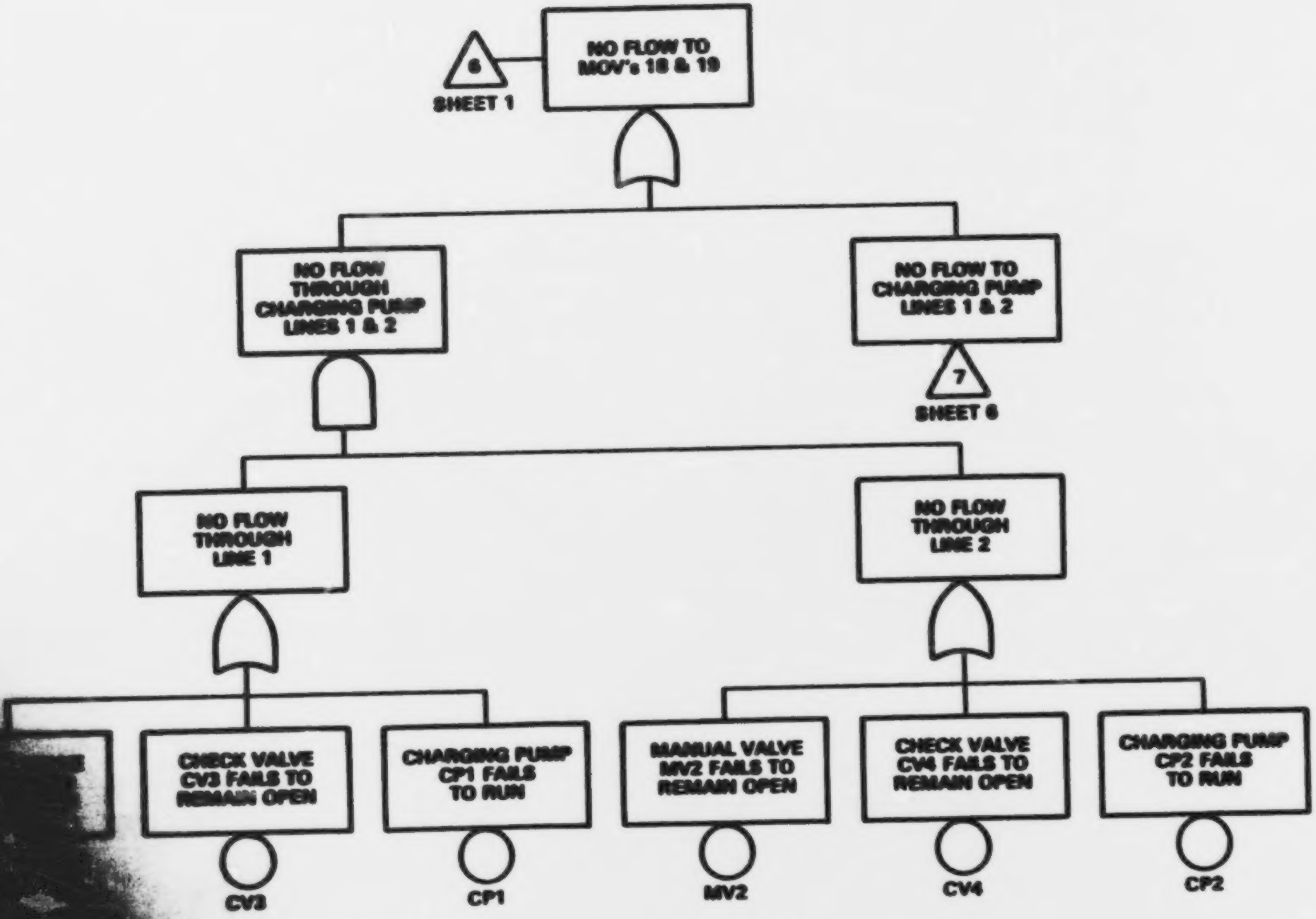

SHEET 1
6
NO FLOW TO MOV's 18 & 19
NO FLOW THROUGH CHARGING PUMP LINES 1 & 2
NO FLOW TO CHARGING PUMP LINES 1 & 2
7
SHEET 6
NO FLOW THROUGH LINE 1
NO FLOW THROUGH LINE 2
CHECK VALVE CV3 FAILS TO REMAIN OPEN
CHARGING PUMP CP1 FAILS TO RUN
MANUAL VALVE MV2 FAILS TO REMAIN OPEN
CHECK VALVE CV4 FAILS TO REMAIN OPEN
CHARGING PUMP CP2 FAILS TO RUN
CV3
CP1
MV2
CV4
CP2

Figure VI-7.B-3. (CONTINUED)

SHEET 5

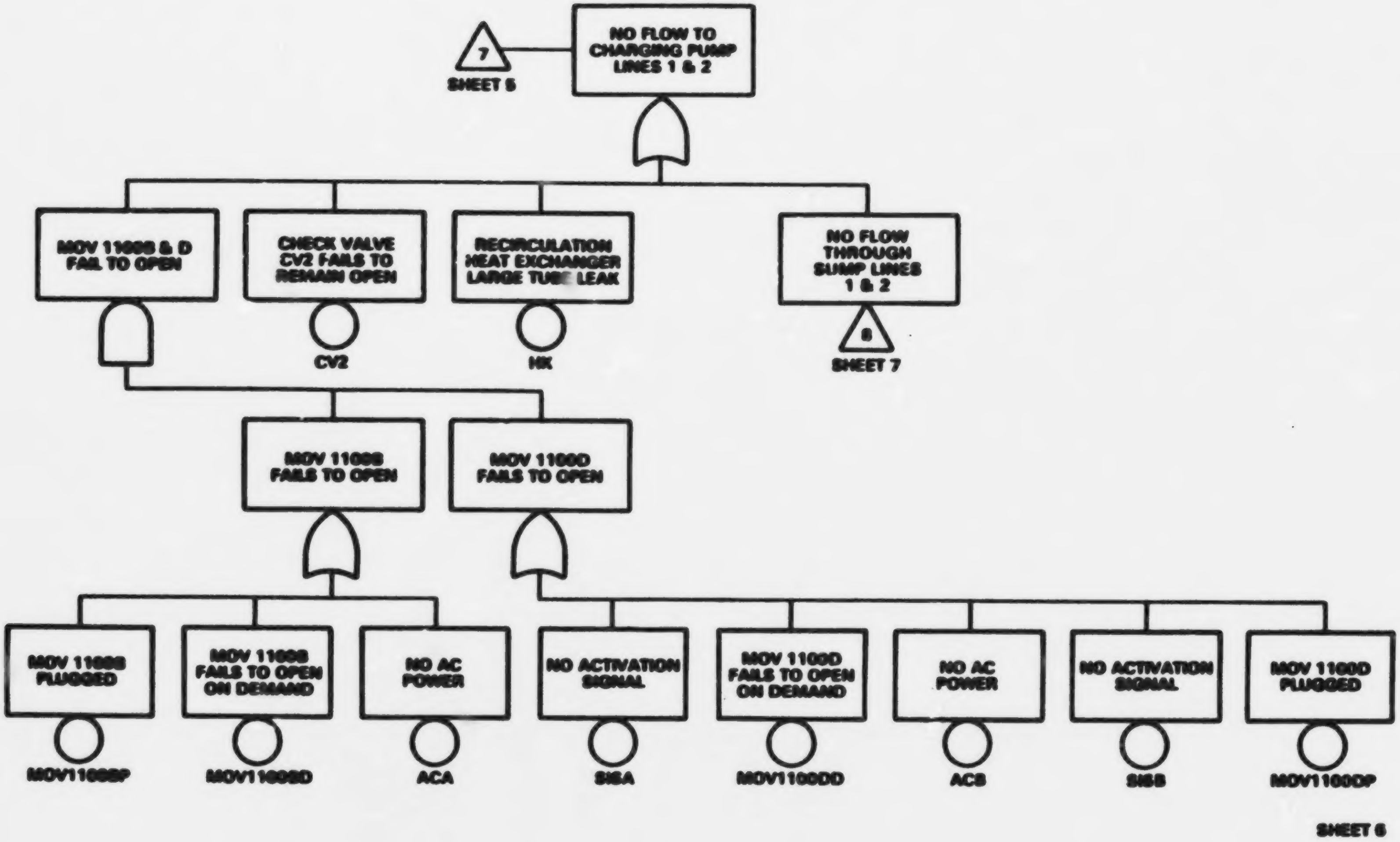
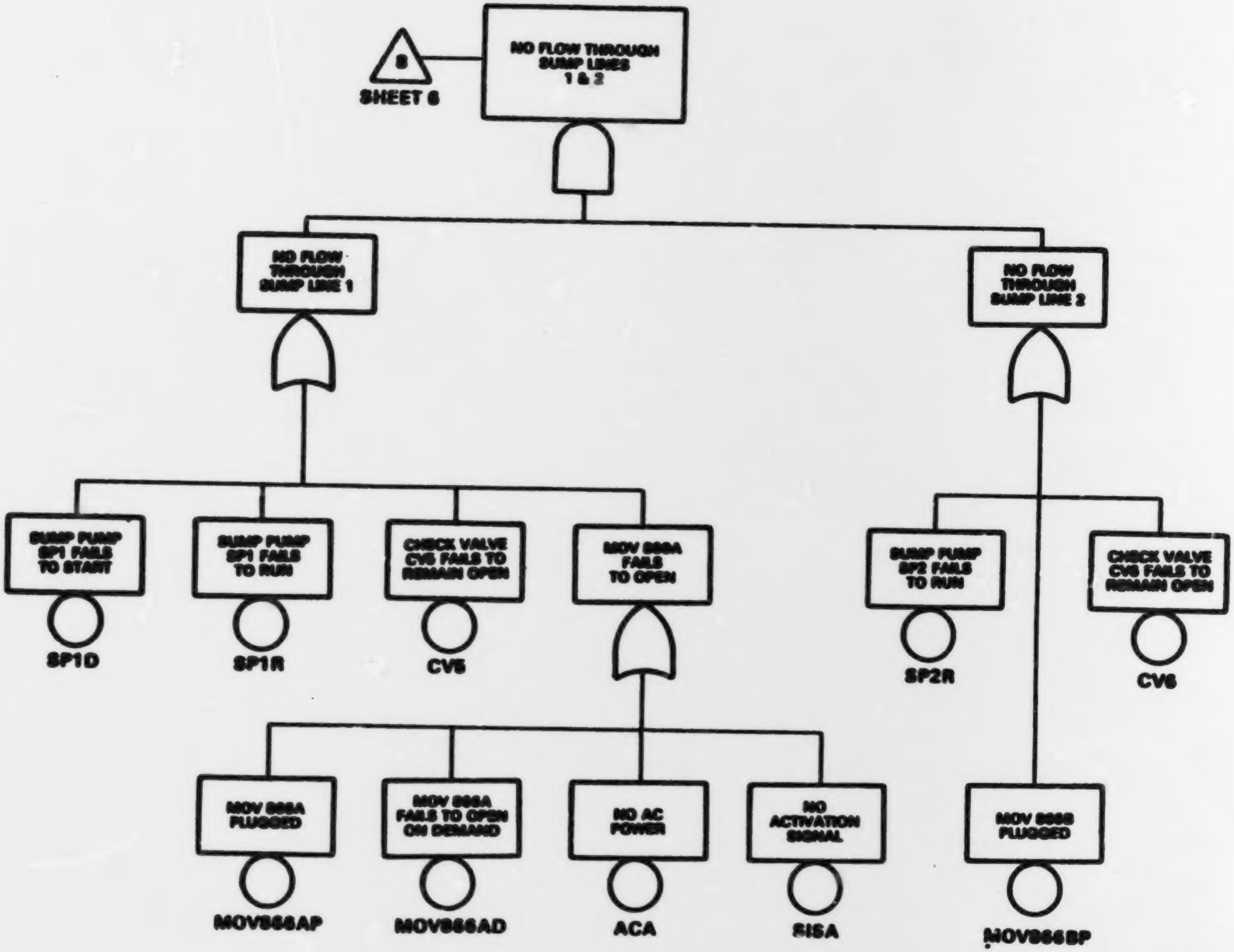

7
SHEET 5
NO FLOW TO CHARGING PUMP LINES 1 & 2
MOV 1100B & D FAIL TO OPEN
CHECK VALVE CV2 FAILS TO REMAIN OPEN
CV2
RECIRCULATION HEAT EXCHANGER LARGE TUBE LEAK
HX
NO FLOW THROUGH SUMP LINES 1 & 2
8
SHEET 7
MOV 1100B FAILS TO OPEN
MOV 1100D FAILS TO OPEN
MOV 1100B PLUGGED
MOV1100BP
MOV 1100B FAILS TO OPEN ON DEMAND
MOV1100BD
NO AC POWER
ACA
NO ACTIVATION SIGNAL
SISA
MOV 1100D FAILS TO OPEN ON DEMAND
MOV1100DD
NO AC POWER
ACB
NO ACTIVATION SIGNAL
SISB
MOV 1100D PLUGGED
MOV1100DP
SHEET 6

Figure VI-7.B-3. (CONTINUED)


B
SHEET 6
NO FLOW THROUGH SUMP LINES 1 & 2
NO FLOW THROUGH SUMP LINE 1
NO FLOW THROUGH SUMP LINE 2
SUMP PUMP SP1 FAILS TO START
SP1D
SUMP PUMP SP1 FAILS TO RUN
SP1R
CHECK VALVE CV5 FAILS TO REMAIN OPEN
CV5
MOV 866A FAILS TO OPEN
SUMP PUMP SP2 FAILS TO RUN
SP2R
CHECK VALVE CV6 FAILS TO REMAIN OPEN
CV6
MOV 866A PLUGGED
MOVS66AP
MOV 866A FAILS TO OPEN ON DEMAND
MOV866AD
NO AC POWER
ACA
NO ACTIVATION SIGNAL
SISA
MOV 866B PLUGGED
MOV866BP

SHEET 7

Figure VI-7.B-3. (CONTINUED)

Table VI-7.B-1 Failure Rates for Various Faults Shown On Figure VI-7.B-3

Fault Identifier	Failure Mode Description	Failure Rate	Fault Duration	Unavailability	Comments
MV1,MV2	Manual valve fails to remain open	1.0×10^{-4}/D	-	1.0×10^{-4}	
MOV358D,MOV357D, MOV356D,MOV18D, MOV19D,MOV2200BD, MOV 1100DD, MOV866AD	Motor Operated Valve does not open on demand	1.0×10^{-3}/D	-	1.0×10^{-3}	
ACA ACB	AC power train A or B unavailable	1.0×10^{-3}/D	-	1.0×10^{-3}	
SISA SISB	Actuation signal train A or B unavailable	1.0×10^{-4}/D	-	1.0×10^{-4}	
MOV358P,MOV357P, MOV356P,MOV18P, MOV19D,OV1100BP, MOV1100DP, MOV866AP,MOV866BP	Motor operated valve plugged	3×10^{-7}/Hr	4380	1.3×10^{-3}	Test for plug annually
CV1,CV2,CV3,CV4, CV5, CV6	Check valve fails to open	1.0×10^{-4}/D	-	1.0×10^{-4}	
AO1115D,AO1115E, AO1115F	Air operated valve fails to remain open	1.0×10^{-4}/D	-	1.0×10^{-4}	

Table VI.7.B-1 Continued

Fault Identifier	Failure Mode Description	Failure Rate	Fault Duration	Unavailability	Comments
HX	Heat exchanger large tube leak	ε	-	ε	Very small probability
SP1	Pump does not start on demand	1.0×10^{-3}/D	-	1.0×10^{-3}	
LX	Failure of the RWST level indicator	5.1×10^{-6}/Hr	4380	2.2×10^{-2}	Annual test

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VI-7.C.2 Failure Mode Analysis ECCS

1. NRC Evaluation

Four items are identified in this issue that require modifications so that the possibility of disabling ECCS due to single failures would be eliminated. These are:

Item 1. Installation of redundant undervoltage relays on each of the 4160V busses 1C and 2C so that automatic start of the diesel generators would not be prevented.

Item 2. Installation of a redundant valve in series with valve MOV/LCV 1100C from volume control tank to the charging pumps. Failure of MOV/LCV 1100C to close may cause cavitation of the two charging pumps downstream of the valve because hydrogen from the volume control tank could enter the sump suction.

Item 3. Modifications to provide independent and redundant hot leg recirculation flow control capability. Loss of any of the five valves in the normal hot leg recirculation flow path could result in loss of this flow path.

Item 4. Installation of redundant control power and instrument air for flow control valves FCV-1115D, E and F. Loss of air pressure or power causes them to close with consequent loss of water transfer to the three cold leg injection lines.

2. NRC Recommendation

The NRC recommendations are based on utilities suggested solutions. The Licensee has completed modifications related to item 1. Item 3 is related to environmental qualification of values and is not appropriate for analysis using PRA techniques. For the other two items, current recommendations are:

Item 2. Install a redundant MOV/LCV valve in series with MOV/LCV 1100C, return the system to its original configuration and retain existing operation procedures

or

install a redundant MOV/LCV valve in series with MOV/LCV 1100C and retain existing (interim modified) station operating procedures.

Item 4. The interim nitrogen supply system currently in place is acceptable as a permanent source of redundant air to FCV 1115, D, E and F if administrative measures are taken to provide control room monitoring of the nitrogen tank pressure and/or annunciator identifications of low pressure condition or the nitrogen tank supply should be replaced by an independent plant air supply. The three way valve should be automated to transfer to the alternate air supply if either supply monitor indicates low pressure or no pressure and an automatic transfer switch should be installed to transfer bus power to the alternate supply as required.

3. Systems Affected

The operation of the charging system, for coolant injection and recirculation, is affected by this issue.

4. Comments

Item 2. The manual operations associated with the initial, interim modified, and NRC recommended electrical and mechanical features of the MOV/LCV 1100C power and control systems dominate the analysis. A range of estimated human error rate, based on WASH 1400 Appendix III data and discussion, is assigned for control room operations in the interpretation of the four possible system configurations following a LOCA. The basic human error rate, 1.0E-1 from WASH-1400 Appendix III, is assigned for operator action to close MOV/LCV 1100C manually. Since these error estimates do not include detailed consideration of actual control room conditions encountered at San Onofre nor time sequences for postulated post LOCA events as related to automatic and station manual operation

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procedure events, two recommended modification options are specified without priority. As discussed in WASH-1400 Appendix III, monthly test intervals are assigned for those system elements for which per hour failure rates are assigned in the same document.

Item 4. Pneumatic pressure is normally supplied at all times to FCV1115 D, E and F by the plant instrument air system or the interim alternate bottled nitrogen system which was added in response to NRC comments. Either of the two systems are connected to the three flow control valves by operation of a manually activated solenoid three-way valve. Thus, failure of this valve due to operator error must be considered.

5. Analysis

Item 2. Figure VI-7.C.2-1 shows a simplified diagram of the piping section of interest to item 2 in the chemical and volume control system (CVCS). The probability of failure of the charging pumps due to failure to isolate the flow path from volume control tank (VCT) to the pumps is analyzed for four cases of interest. In this first case the original configuration of the system is analyzed. In this case, upon receiving a safety injection (SI) signal, MOV/LCV 1100C should close automatically. If the valve does not close due to lack of electrical power from MCC1, the auto transfer switch should automatically switch to MCC2.

The failure probability of the flow path from the VCT to the charging pumps is the probability that MOV/LCV 1100C fails to close upon receiving an SI signal. This can be evaluated by the following expression:

$$PFI = PMVI = P1I + PMECH$$

where,

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PFI = Probability of flow path failing from the VCT to the charging pumps for case I

PMVI = Probability of MOV/LCV 1100C failing to close given an SI signal for case I

P1I = Probability of loss of power to MOV (motor operated valve MOV/LCV 1100C)

PMECH= Probability MOV fails to close on demand due to mechanical failure

P1I is calculated as follows:

P1I = PMCC1 x (PAUTO + PMCC2)

where,

PMCC1 = Failure probability of BUS MCC1

PMCC2 = Failure probability of BUS MCC2

PAUTO = Failure of automatic transfer system

therefore,

PFI = PMVI = [PMCC1 x (PAUTO + PMCC2)] + PMECH

Using the failure rates shown in Table VI-7.C.2-1 (WASH-1400), the above expression can be quantified as:

PFI = 3E-6 x (1E-4 + 3E-6) + 1E-3
PFI = 1E-3

Thus, given occurrence of a small LOCA with a frequency of 1.0×10^{-3}/year (WASH-1400), if the MOV/LCV 1100C is not closed on time the charging pumps can be disabled with a probability of 1.0×10^{-3} and long term recirculation will be lost. This results in a core melt frequency of 1.0×10^{-6}/year.

The second case analyzed is the existing configuration of the system which has been implemented by the licensee to eliminate this problem. In this case the automatic transfer of MCC1 to MCC2 is eliminated by two operator actions. In addition, one of the charging pumps was removed from the list of components which are automatically started by a sequencer following initiation of an accident. This will eliminate the possibility of one of the pumps being cavitated before the recirculation is established.

Thus, in this case two failures must occur before the ECCs system fails due to the loss of the charging pumps: (1) MOV/LCV 1100C must fail to close, and (2) the charging pump that is removed from starting automatically upon receiving an SI signal must fail to start during the recirculation phase. The failure probability of the charging pumps in this case can be expressed as:

PTII = PMVII x PCP

where,

PTII = Failure of ECCS due to loss of charging pump contributions

PMVII= Probability of MOV/LCV 1100C failing to close given an SI signal for case II

PCP = Failure of a charging pump to start on demand

PMVII= PMCC1 * (P1II + P2II + PMCC2) * P3II + PMECH

where,

P1II = Failure of operator to manually transfer to MCC2

P2II = Failure of operator to manually close racked out circuit breaker

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P3II = Failure probability of operator to go on manually close MOV/LCV 1100C if it does not close

PCP = Failure of charging pump to start on demand

therefore,

PTII = [(3E-6 x (1E-2 + 1E-2 + 3E-6) x 1E-1) + 1E-3] x (1E-3)

PTII = 1E-6

Based on this the probability of core melt is 1.0×10^{-9}/year.

The third case is the configuration proposed by the NRC where a second MOV is added to the piping from VCT in series with MOV/LCV 1100C. Thus, this case is the same as case I, except that an extra MOV is installed in series with MOV/LCV 1100C. The failure of the flow path from the VCT to the charging pumps then becomes:

PFIII = P1I + (PMECH x PMECH)

where,

PFIII = The probability of the flow path failing from the VCT to the charging pumps for case III

P1I = The probability of the loss of power to MOVs

PMECH= Failure probability of the extra MOV to close on demand due to mechanical failure (same as for MOV/LCV 1100C)

After quantifying the above expression we get:

PFIII = 3E-6 x (1E-4 + 3E-6) + (1E-3) x (1E-3)

PFIII = 1E-6

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This failure probability is the same as Case II and results in a core melt probability of $1.0x10^{-9}$/year.

The last case is the same as Case II, except that a MOV is added in series with MOV/LCV 1100C. The failure probability of the charging pumps in this case can be expressed as:

PTIV = PMCC1 x (P1II + P2II + PMCC2) x P3II + (PMECH x PMECH) x PCP

where,

PTIV = Failure of ECCS due to loss of charging pump contributions

PTIV = [3E-6 x (1E-2 + 1E-2 + 3E-6) x (1E-1) + (1E-3) (1E-3)] (1E-3)

PTIV = 1E-9

The core melt probability in this case would be $1.0x10^{-12}$/year.

The results for the four cases above are summarized here:

CASE	CONFIGURATION	SYSTEM FAILURE DUE TO CHARGING PUMP CAVITATION
I	Initial system	1E-3
II	Interim System Modification	1E-6
III	NRC Requested Modification	1E-6
IV	Current Interim System with a MOV added in Series	1E-9

Item 4. Figure VI-7.C.2-2 is a simple schematic diagram of the electrical monitor and control systems for the electrical supplies and of the air and nitrogen pneumatic supplies to FCV 1115 D, E and F.

The failure probability of the air supply system can be expressed as:

FAS = FPIR * (FNEAS + FMATV)

where,

FAS = failure probability of the air supply system

FPIR = failure probability of the plant instrument air system

FNEAS = failure probability of the new emergency air supply system

FMATV = failure probability of the manual air transfer valve

The failure of the plant instrument air system is equal to

FPIR = FREG1 + FVP + FCV1

where,

FREG1 = failure of the regulator 1

FVP = failure of the valve positioner

FCV1 = failure of the check valve 1

The failure probability of the new emergency air supply system is equal to

FNEAS = FREG2 + FEPC

where,

FREG2 = failure probability of the regulator 2

FEPC = failure probability of the electric/pneumatic converter

Using the data shown in Table VI-7.C.2-1 the expression for the failure of the air supply system can be quantified as

$$\text{FAS} = (1.7\text{E-}2 + 7.8\text{E-}3 + 1.0\text{E-}4) * [(1.7\text{E-}2 + 8.7\text{E-}3) + 1.0\text{E-}2]$$

where failure of the manual air transfer valve is assumed to be dominated by the basic human error of 1.0E-2. This results in a failure probability of the air supply of 8.8E-4. The failure of the air supply will result in failure of the ECCS in the recirculation mode. Based on a small LOCA frequency of 1.0E-3/year and air supply failure of 8.8E-4 a core melt frequency of 8.8E-7/year would result. If the manual air transfer valve is replaced by an automatic transfer sytem with a failure probability of 1.0E-4, the failure of the air supply system reduces to 5.3E-4. Note that the effect of replacing the manual switchover by an automatic system is not very high because of the dominance of the failure of either air supply system by failure of the regulator. The failure of the regulator is high because of the assumption about annual testing of this component. In the old configuration where there was no redundancy in the air supply system, various components of the system could not be tested frequently. In the new configuration where redundancy in the air supply system is added, more frequent testing of the components, for example on a monthly basis, can be performed. This would reduce the unavailability of the air supply system considerably.

6. Conclusion

Item 2. Failure of the MOV/LCV 1100C to close resulting in possible cavitation of the charging pumps in the present configuration could result in a core melt frequency of 1.0E-6. The proposed changes by the licensee reduces this core melt frequency by three orders of magnitude. This reduction can also be realized if the configuration is changed to the NRC recommended configuration.

Item 4. The probability of failure of the air supply system with the licensee proposed changes is in the order of 8.8E-4. This could lead to a core melt frequency of 8.8E-7/year. Further modification of this configuration by replacing the manual air transfer valve by an automatic transfer system reduces the possible core melt frequency to 5.3E-7/year. Additional reduction in failure probability of this system can be realized if the components of the system are tested more frequently. Overall, without any proposed modifications, the risk significance of this issue would be ranked medium. With the above modifications in place the risk significance of this issue reduces to low.

Table VI-7.C.2-1 Failure Rates for Various Faults Related to Failure of the Charging Pumps and Air Operated Valves

Fault Identifier	Failure Mode Description	Failure Rate	Fault Duration (Hrs)	Unavailability	Comments
PMCC1	Failure of MCC1	E-7/h^{r}	24	3E-6	Based on a 24 hour period
PMCC2	Failure of MCC2	E-7/hr	24	3E-6	
PAUTO	Failure of automatic transfer bus	1E-4/d		1E-4	
PMECH	Mechanical failure of MOV	1E-3/^{d}		1E-3	
P1II	Operator failure to perform manual transfer	1E-2		1E-^{2}	
P2II	Operator failure to close circuit breaker	1E-2		1E-2	
P3II	Operator failure to close MOV	1E-1		1E-1	
PCP	Charging pump fails to start	1E-3/d		1E-3	
FREG	Failure of regulator	4E-6/hr	4380	1.7E-2	Based on annual test
FVP	Failure of valve positioner	1.8E-6/hr	4380	7.8E-3	Based on annual test
CV1,CV2	Failure of the check valve	1E-4/d		1E-4	
FEPC	Failure of E/P Converter	1E-6/hr	4380	8.7E-3	Based on annual test

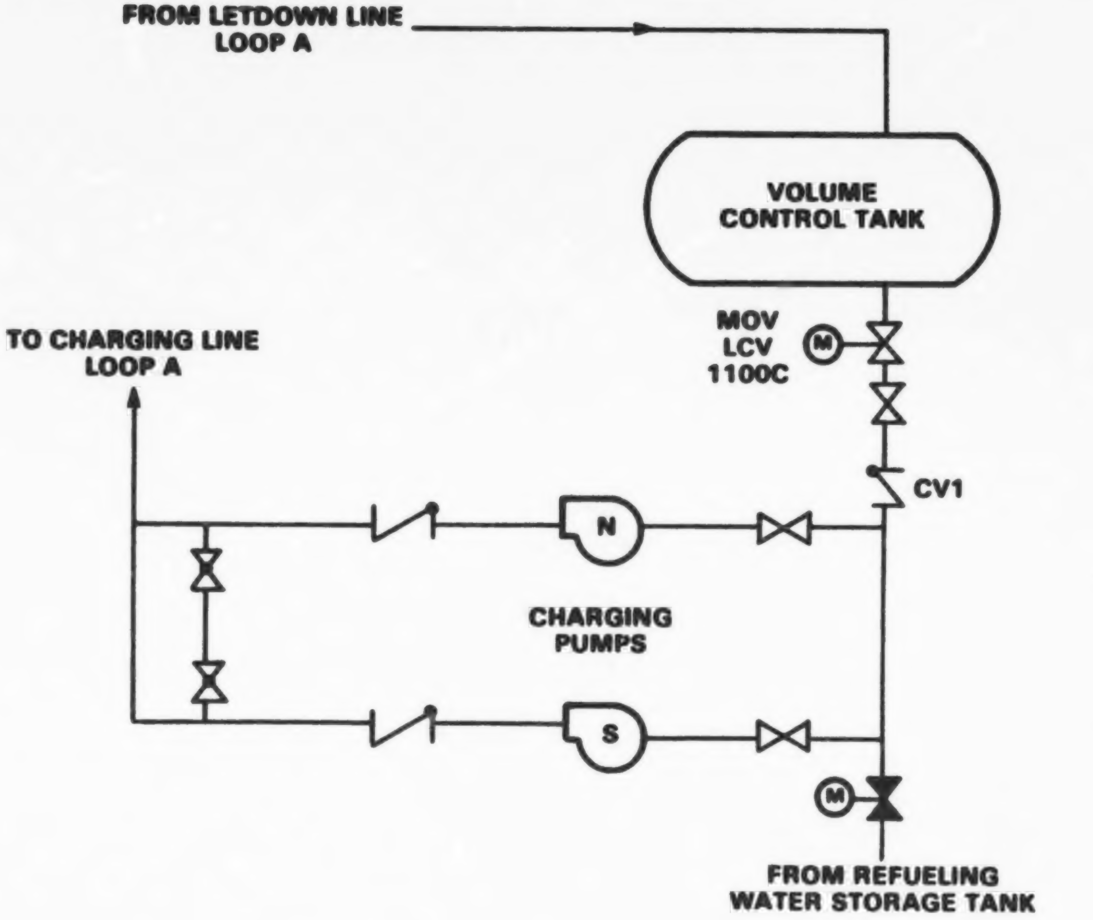
FROM LETDOWN LINE
LOOP A
VOLUME
CONTROL TANK
MOV
LCV
1100C
M
CV1
TO CHARGING LINE
LOOP A
N
CHARGING
PUMPS
S
M
FROM REFUELING
WATER STORAGE TANK

Figure VI-7.C-2-1. SIMPLIFIED SCHEMATIC OF A SECTION OF THE CVCS

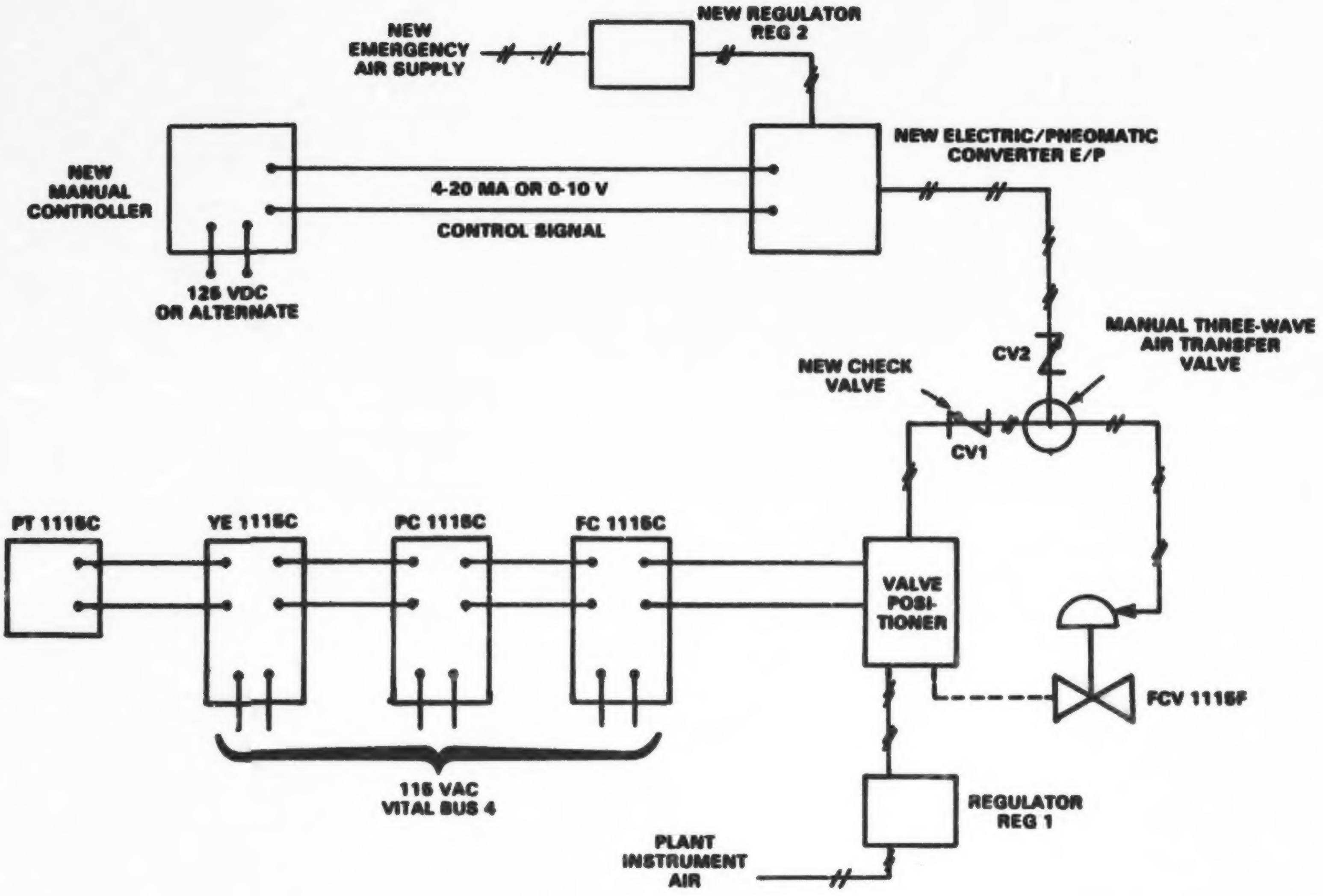
NEW EMERGENCY AIR SUPPLY
NEW REGULATOR REG 2
NEW MANUAL CONTROLLER
4-20 MA OR 0-10 V
CONTROL SIGNAL
NEW ELECTRIC/PNEOMATIC CONVERTER E/P
125 VDC OR ALTERNATE
MANUAL THREE-WAVE AIR TRANSFER VALVE
CV2
NEW CHECK VALVE
CV1
PT 1115C
YE 1115C
PC 1115C
FC 1115C
VALVE POSI-TIONER
FCV 1115F
115 VAC VITAL BUS 4
REGULATOR REG 1
PLANT INSTRUMENT AIR

Figure VI-7.C-2-2. NEW REDUNDANT AIR SUPPLY SYSTEM FOR THE AIR OPERATED VALVES FCV 1115D, E, F

VI-10.A Testing of Reactor Trip System and Engineered Safety Features, Including Response Time Testing

1. NRC Evaluation

The Technical Specifications for San Onofre Unit No. 1 were compared with the standard technical specifications for current pressurized water reactor licensing. It was found that, for the reactor trip system, one signal is not subjected to a channel functional test as frequently as required in the standard technical specifications; seven channels are not checked, tested or calibrated as required in the standard technical specifications; and several channels that are part of the RTS for the standard technical specifications are not part of the San Onofre Unit 1 RTS. Additionally, the channel response time between channel trip and the operation of the reactor trip relay is not required to be tested.

For the Containment Spray System, selected as typical of ESF systems surveillance requirements were non-existant for systems that are required to operate in support of the containment spray system.

2. NRC Recommendations

The licensee should implement a program for response time testing of all reactor protection systems (including engineered safety features systems such as containment isolation). In addition, the licensee should amend the Technical Specifications to correct for the other omissions noted above (Section 1. NRC Evaluation).

3. Systems Affected

The systems affected by this issue are the RPS and the ESF actuation systems.

4. Comments

The important aspect of response time testing to be considered when examining its impact on risk is the relatively short time period involved in the response time test. The time involved in response time testing is normally on the order of a few seconds. When considering the operability of a system in a risk analysis the time constraints on system operation are considerably longer than a few seconds. System operation in time intervals greater than a few seconds can be considered a successful operation of the system, i.e., the system performs its function to prevent a core melt. With this amount of time available, the short time periods measured in response time testing are not significant. Therefore, it can be said that response-time testing does not affect overall plant risk. No further analysis of this issue is required. Any functional test will demonstrate ability to function within seconds or minutes, since the test would be called a failure ong before those excessive amounts of time had passed. This argument applies also to ECCS systems. In the Interim Reliability Evaluation Program (IREP) study of Millstone Unit 1, it was determined that an ECCS System was successful, from the point of preventing core melt, if it was in operation within one-half hour.

The issue of channel checks is somewhat similar, although in the opposite sense. In the case of channel checks, they do not actually test the functioning of the actuation signals, since no components are actually caused to change state to represent an accident condition. Thus, in doing a PRA, channel checks do not affect the failure rate of any equipment since they do not alter the time between real (i.e., functional) tests. No further analysis of this issue is required.

5. Analysis

No analysis is required for this topic.

6. Conclusion

The issues discussed have no effect on component or system reliability, therefore, on risk from core melt. This is because the NRC recommendations do not serve to increase surveillance from a PRA standpoint. For this reason we rank the importance of this issue as low.

VII-1.A Isolation of Reactor Protection System from Non-Safety Systems

1. NRC Evaluation

Current criteria requires that non-safety systems receiving output from the reactor protection system (RPS) have isolation devices to insure the independence of the RPS channels. San Onofre 1 complies with the current licensing criteria except for the following. There are no isolation devices between the remote meters and process recorders and 1) the pressurizer pressure trip logic, 2) the pressurizer level trip logic, 3) the steam-to-feedwater flow mismatch trip signal, 4) the startup rate neutron monitoring system, and 5) the high flux level trip signal. Additionally there is no isolation device between the data logger and the nuclear instrumentation, and between the steam-to-feedwater flow mismatch system and the Optimac computer.

2. NRC Recommendation

The adequacy of the present design should be justified by the licensee or suitably qualified isolators should be installed at the San Onofre 1 plant.

3. Systems Affected

The only system affected by this issue is the reactor protection system (RPS).

4. Comments

Both the pressurizer pressure and level trip signals lack the same isolation devices. Each of the three trip channels for these two trip signals lacks proper isolation from an indicating meter. Additionally there is a recorder that can be connected to the trip channels (any one of the three) that is not properly isolated from any of the trip channels. An electrical failure of the recorder could conceivably affect all three channels.

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In the steam generator steam-to-feedwater flow mismatch trip channels each of the three trip channels output to a process recorder. The recorder is not properly isolated. A level and flow controller also receives a signal from all three flow mismatch trip channels and is not properly isolated.

The final area where proper isolation may not be present is the nuclear instrumentation channels. Recorders and the data logger may not be properly isolated from the source range and intermediate range nuclear channels. Each of the four power range channels (including the intermediate channel) is connected to control room power level indicators. Proper isolation may not exist between the power range channels and the indicators. Also there are two dual pen recorders that can be used for any of the power range channels.

Information from plant personnel indicates that the data logger referenced for the intermediate power range trip channel is not used at San Onofre 1 and does not receive an output signal from the intermediate range nuclear channel. Also the reactor coolant flow channels are of similar design to the pressurizer level and pressure channels. The reactor coolant flow indicators receive an output from the reactor coolant flow trip channels and are not isolated. The effects of the lack of isolation on this trip signal are therefore addressed in this analysis.

5. Analysis

A trip signal from any one of the five trip parameters being analyzed here (high flux, pressurizer pressure, pressurizer level, coolant flow, and steam-to-feedwater flow mismatch) will cause a reactor trip. The startup rate channel will produce either a reactor trip or a rod withdrawal block. Each of the four high flux channels consists of two flux monitors, an amplifier, a bistable and relay. To trip the reactor two of the four high flux level channels must generate a trip signal. The three channels of the pressurizer pressure, pressurizer level, coolant flow and steam to feedwater flow mismatch trip logic are combined in a two out of three logic; to generate a trip signal two of the three channels for any parameter must indicate a trip condition. Each of the channels for these parameters consist essentially of a relay, bistable and the appropriate sensor

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transmitter (flow, level, pressure). The steam-to-feedwater flow mismatch channels each contain two flow transmitters.

Using this information a simplified fault tree for these trip signals was produced. This fault tree is shown in Figure VII-1.A-1. The circuitry required to produce a two out of three or two out of four logic is not specifically modelled. However, this should not significantly affect the analysis of the contribution of faults in unisolated non-safety systems to RPS failure.

The unisolated system faults can affect the trip signals in two ways. In the case of meters and indicators attached to a particular channel the unisolated fault in the meter will affect only that channel. The recording devices that can be used on multiple channels for a particular trip parameter were assumed to be able to affect all of the channels for that trip parameter. For example, a fault in the two dual pen recorders used in the high flux channels was assumed to affect all four high flux channels. The unisolated faults are modelled in the fault tree shown in Figure VII-1.A-1.

Data for this analysis is shown in Table VII-1.A-1. This data is developed from IEEE STD 500-1977. The test intervals are taken from the information provided for Topic VI-10.A. Since it has been assumed that the unisolated faults in the recorders, meters, etc. affect the performance of the RPS these faults would be detected during the RPS channel functional tests. Therefore the test interval is the same for these faults as for the RPS channel equipment.

Not all of the trip signals can be expected during all transients. Therefore, the fault tree was analyzed for two relatively restrictive cases. In one the trip signals assumed to be present were: pressurizer pressure[1], pressurizer level, high flux and steam-to-feedwater flow mismatch (conditions present in a transient such as a loss of feedwater). The second case (representative of a transient such as a loss of coolant flow) assumed that the following trip signals would be present: pressurizer pressure, pressurizer level, high flux, and coolant flow.

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[1] The unisolated faults would affect both high and low pressurizer pressure trips. Therefore, the fault tree models an off normal pressurizer condition since an unisolated fault is assumed to fail the pressure signal.

For both of these cases the failure probability of the RPS due to failure combinations that contain unisolated faults in non-safety systems is less than 1E-10. The combination of faults that would fail only the nuclear instrumentation and pressurizer signals is on the order of magnitude of 1E-9. In most previous PRAs the failure rate used for the RPS has been on the order of 3E-5. This is due primarily to the common mode mechanical failure of the control rods to insert. It is reasonable to assume that the failure to scram probability for the San Onofre 1 plant would be similar to that for other PWRs. Therefore, the contribution (of less than 1E-10) of unisolated faults in non safety systems would be negligible.

The lack of isolation in the high start up rate instrumentation has not been specifically modelled for this analysis. However, the effects on that signal should be similar to those for the high flux signal since in both cases an unisolated fault would fail that signal. The lack of isolation in the high start up rate instrumentation should not significantly affect the RPS failure probability.

6. Conclusion

The lack of isolation between the RPS and the non-safety systems does not significantly affect the RPS failure probability. It will therefore have virtually no effect on the expected core melt frequency. We rate this issue to be of low risk signficance.

Table VII-1.A-1

Component	Failure Rate $\lambda_o(hr^{-1})$	Test Interval (hr)	Unavailability
Flux Channels			
Neutron Flux Detector	1.4E-5	168	1.2E-3
Bistable	3.0E-6	168	2.5E-4
Relay	3.0E-6	168	2.5E-4
Amplifier	2.3E-6	168	1.9E-4
Power Level Indicator	4.6E-6	168	3.9E-4
Recorder	6.8E-6	168	5.7E-4
Steam-to-Feedwater Flow Mismatch Channels			
Pressurizer Pressure Channels			
Pressurizer Level Channels			
Flow Transmitter	6.0E-6	336	1.0E-3
Level Transmitter	5.1E-6	336	8.6E-4
Pressure Transmitter	5.7E-6	336	9.5E-4
Relay	3.0E-6	336	5E-4
Bistable	3.0E-6	336	5E-4
Recorder (all types)	6.8E-6	336	1.1E-3
Meter	4.6E-6	336	7.7E-4
Flow/Level Controller	2.3E-6	336	3.4E-4
Coolant Flow Channel			
Flow Transmitter	6.0E-6	2190	6.6E-3
Relay	3.0E-6	2190	3.2E-3
Bistable	3.0E-6	2190	3.2E-3
Meter	4.6E-6	2190	5.0E-3

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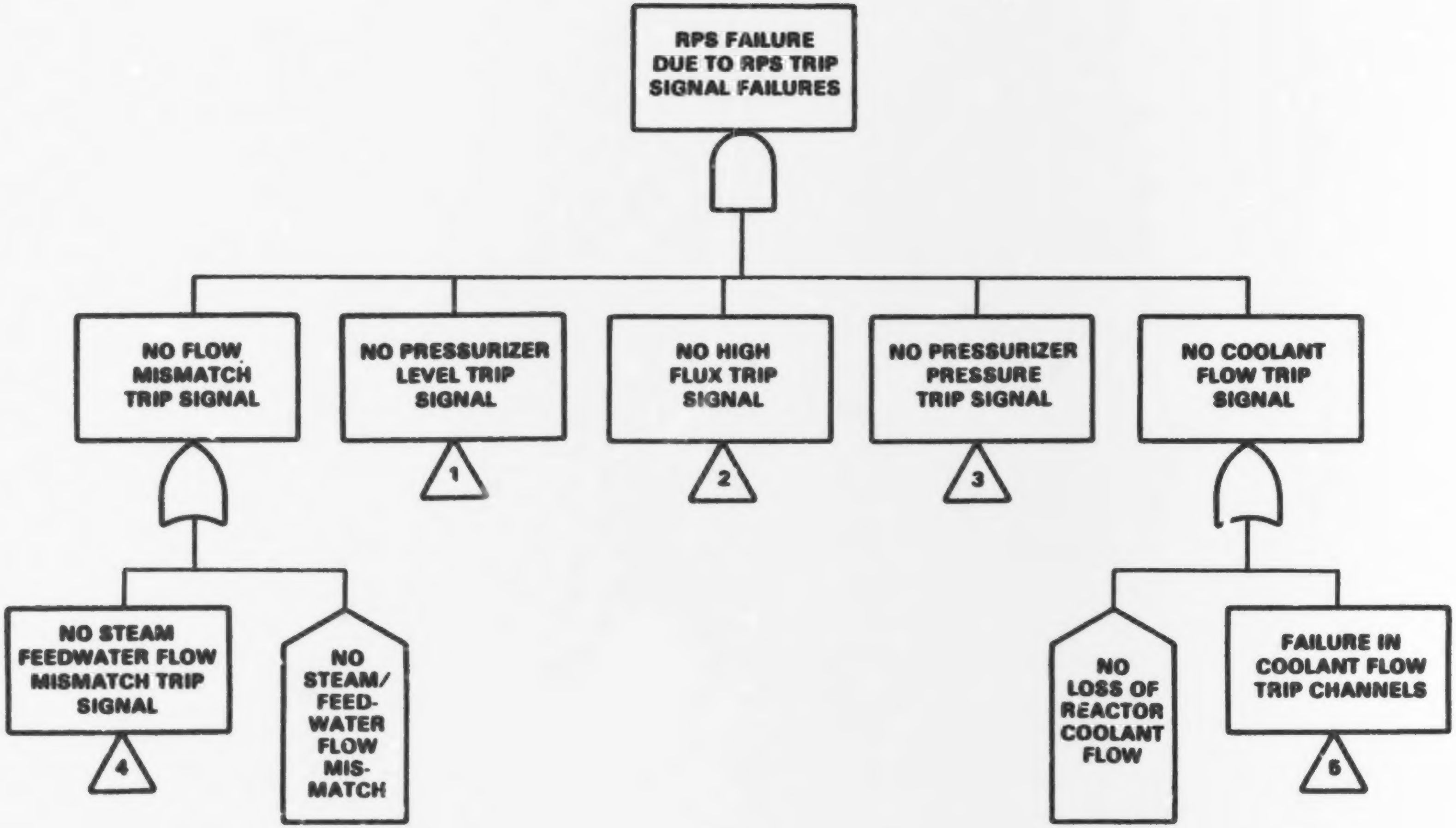
RPS FAILURE DUE TO RPS TRIP SIGNAL FAILURES
NO FLOW MISMATCH TRIP SIGNAL
NO PRESSURIZER LEVEL TRIP SIGNAL
1
NO HIGH FLUX TRIP SIGNAL
2
NO PRESSURIZER PRESSURE TRIP SIGNAL
3
NO COOLANT FLOW TRIP SIGNAL
NO STEAM FEEDWATER FLOW MISMATCH TRIP SIGNAL
4
NO STEAM/ FEED-WATER FLOW MIS-MATCH
NO LOSS OF REACTOR COOLANT FLOW
FAILURE IN COOLANT FLOW TRIP CHANNELS
5

Figure VII-1.A-1. SIMPLIFIED RPS FAULT TREE FOR THE CONTRIBUTION OF UNISOLATED NON SAFETY SYSTEM FAULTS

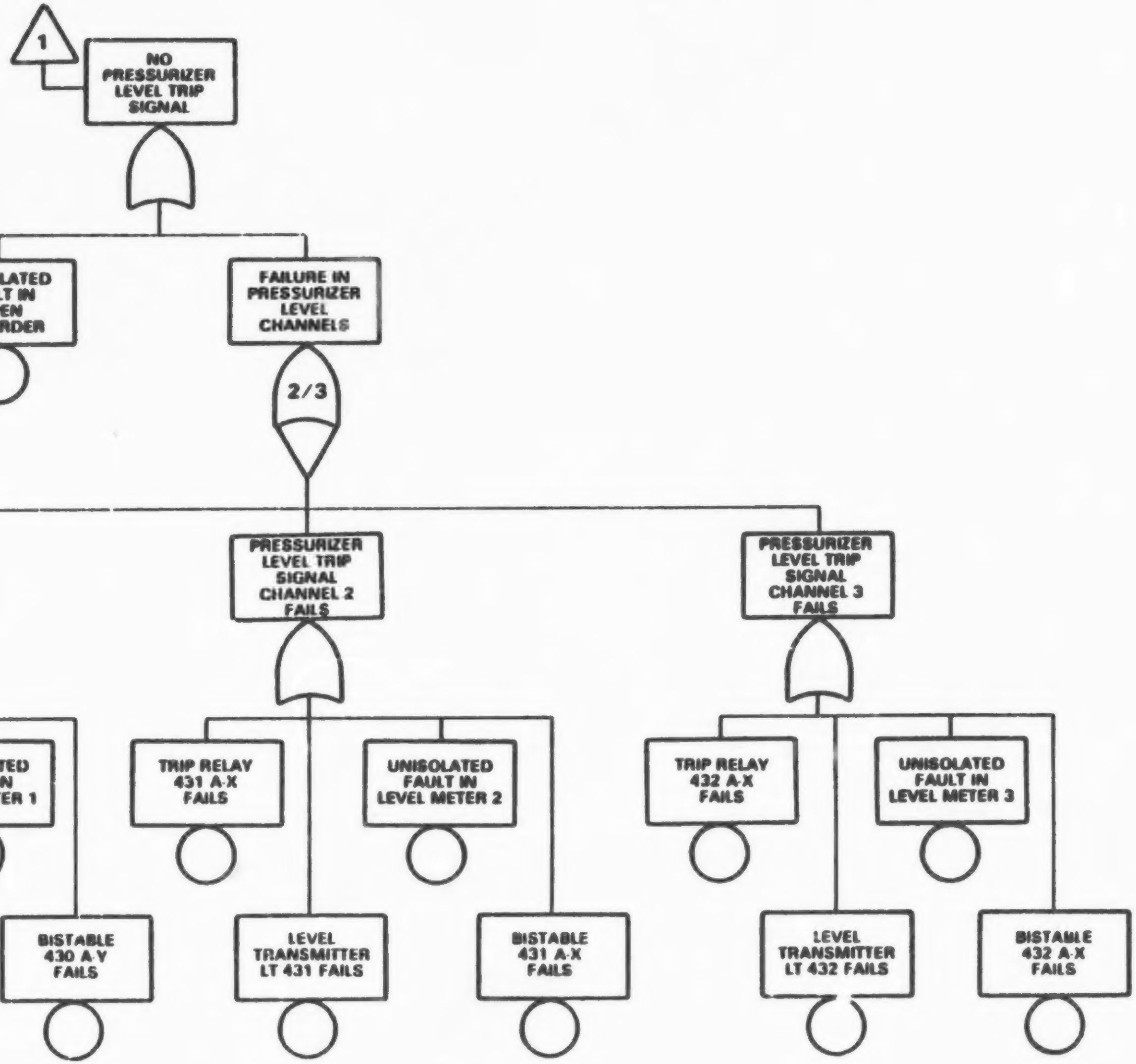
1
NO PRESSURIZER LEVEL TRIP SIGNAL
UNISOLATED FAULT IN 2 PEN RECORDER
FAILURE IN PRESSURIZER LEVEL CHANNELS
2/3
NO TRIP SIGNAL FROM PRESSURIZER LEVEL CHANNEL 1
PRESSURIZER LEVEL TRIP SIGNAL CHANNEL 2 FAILS
PRESSURIZER LEVEL TRIP SIGNAL CHANNEL 3 FAILS
TRIP RELAY 430 A X FAILS
UNISOLATED FAULT IN LEVEL METER 1
LT 430 (LEVEL TRANSMITTER) FAILS
BISTABLE 430 A-Y FAILS
TRIP RELAY 431 A-X FAILS
UNISOLATED FAULT IN LEVEL METER 2
LEVEL TRANSMITTER LT 431 FAILS
BISTABLE 431 A-X FAILS
TRIP RELAY 432 A-X FAILS
UNISOLATED FAULT IN LEVEL METER 3
LEVEL TRANSMITTER LT 432 FAILS
BISTABLE 432 A-X FAILS

Figure VII-1.A-1. (CONTINUED)

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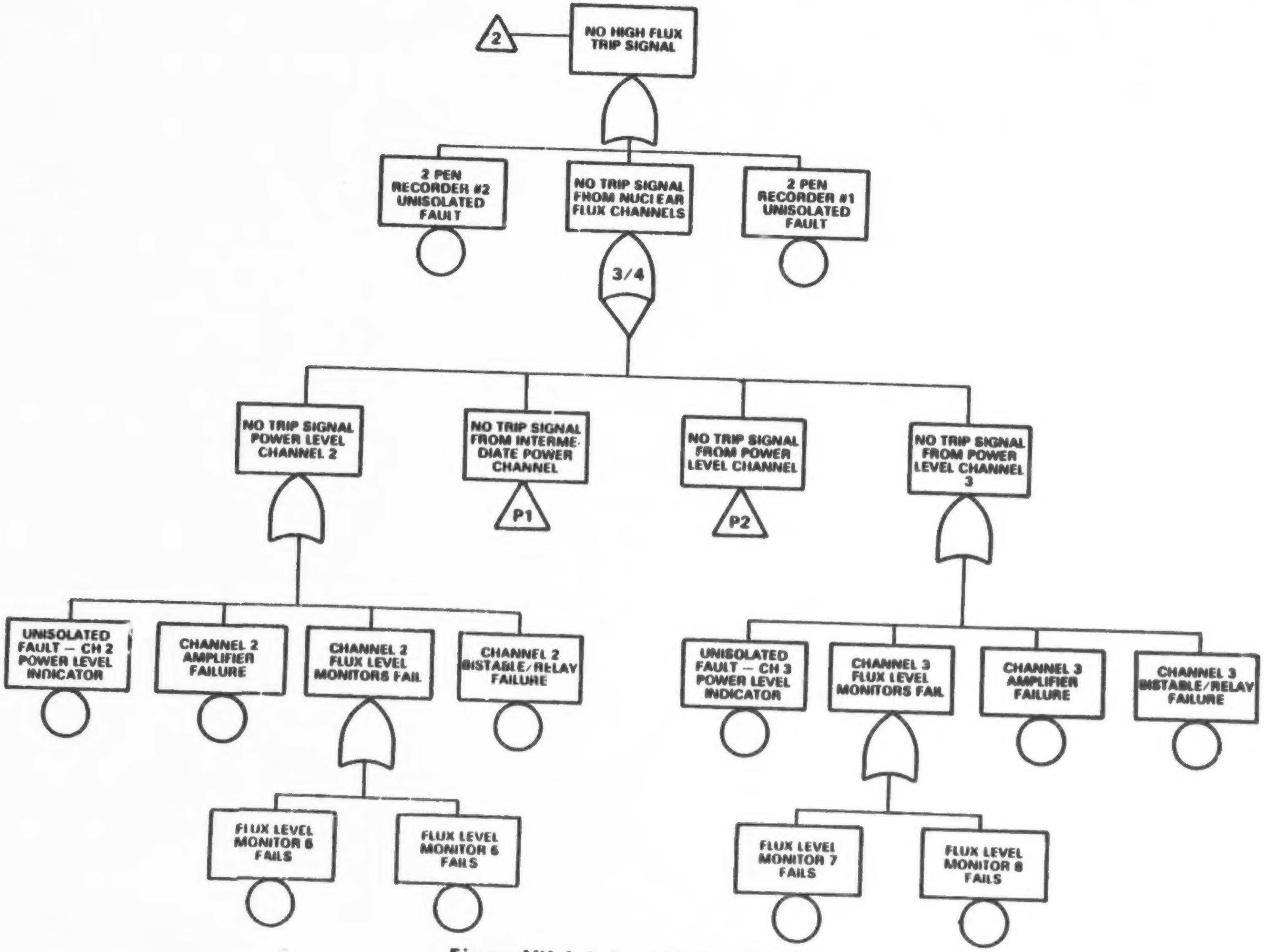
2
NO HIGH FLUX TRIP SIGNAL
2 PEN RECORDER #2 UNISOLATED FAULT
NO TRIP SIGNAL FROM NUCLEAR FLUX CHANNELS
2 PEN RECORDER #1 UNISOLATED FAULT
3/4
NO TRIP SIGNAL POWER LEVEL CHANNEL 2
NO TRIP SIGNAL FROM INTERMEDIATE POWER CHANNEL
P1
NO TRIP SIGNAL FROM POWER LEVEL CHANNEL
P2
NO TRIP SIGNAL FROM POWER LEVEL CHANNEL 3
UNISOLATED FAULT — CH 2 POWER LEVEL INDICATOR
CHANNEL 2 AMPLIFIER FAILURE
CHANNEL 2 FLUX LEVEL MONITORS FAIL
CHANNEL 2 BISTABLE/RELAY FAILURE
UNISOLATED FAULT — CH 3 POWER LEVEL INDICATOR
CHANNEL 3 FLUX LEVEL MONITORS FAIL
CHANNEL 3 AMPLIFIER FAILURE
CHANNEL 3 BISTABLE/RELAY FAILURE
FLUX LEVEL MONITOR 5 FAILS
FLUX LEVEL MONITOR 6 FAILS
FLUX LEVEL MONITOR 7 FAILS
FLUX LEVEL MONITOR 8 FAILS

Figure VII-1.A-1. (CONTINUED)

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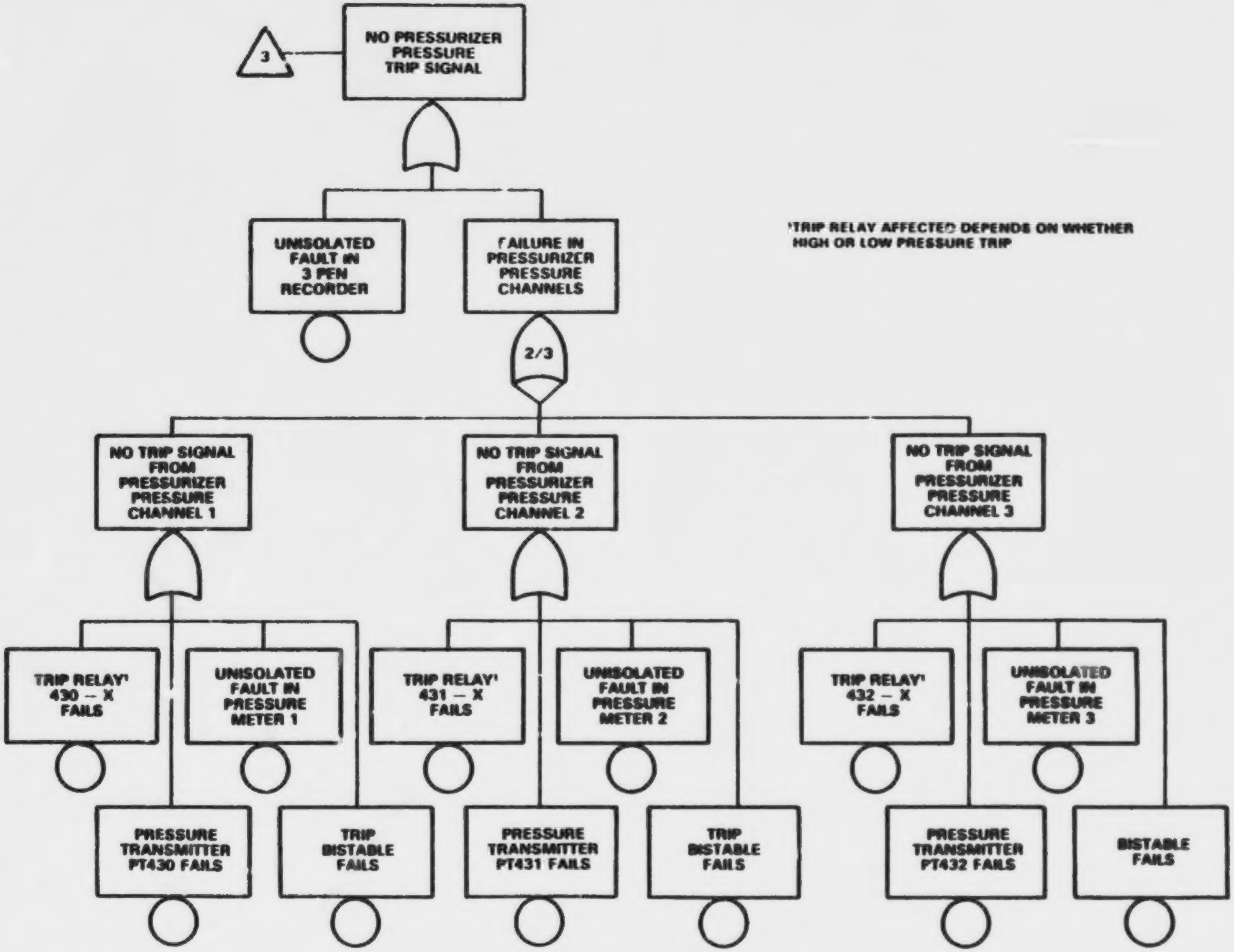
3
NO PRESSURIZER PRESSURE TRIP SIGNAL
UNISOLATED FAULT IN 3 PEN RECORDER
FAILURE IN PRESSURIZER PRESSURE CHANNELS
2/3
NO TRIP SIGNAL FROM PRESSURIZER PRESSURE CHANNEL 1
NO TRIP SIGNAL FROM PRESSURIZER PRESSURE CHANNEL 2
NO TRIP SIGNAL FROM PRESSURIZER PRESSURE CHANNEL 3
TRIP RELAY' 430 — X FAILS
UNISOLATED FAULT IN PRESSURE METER 1
TRIP RELAY' 431 — X FAILS
UNISOLATED FAULT IN PRESSURE METER 2
TRIP RELAY' 432 — X FAILS
UNISOLATED FAULT IN PRESSURE METER 3
PRESSURE TRANSMITTER PT430 FAILS
TRIP BISTABLE FAILS
PRESSURE TRANSMITTER PT431 FAILS
TRIP BISTABLE FAILS
PRESSURE TRANSMITTER PT432 FAILS
BISTABLE FAILS

'TRIP RELAY AFFECTED DEPENDS ON WHETHER HIGH OR LOW PRESSURE TRIP

Figure VII-1.A-1. (CONTINUED)

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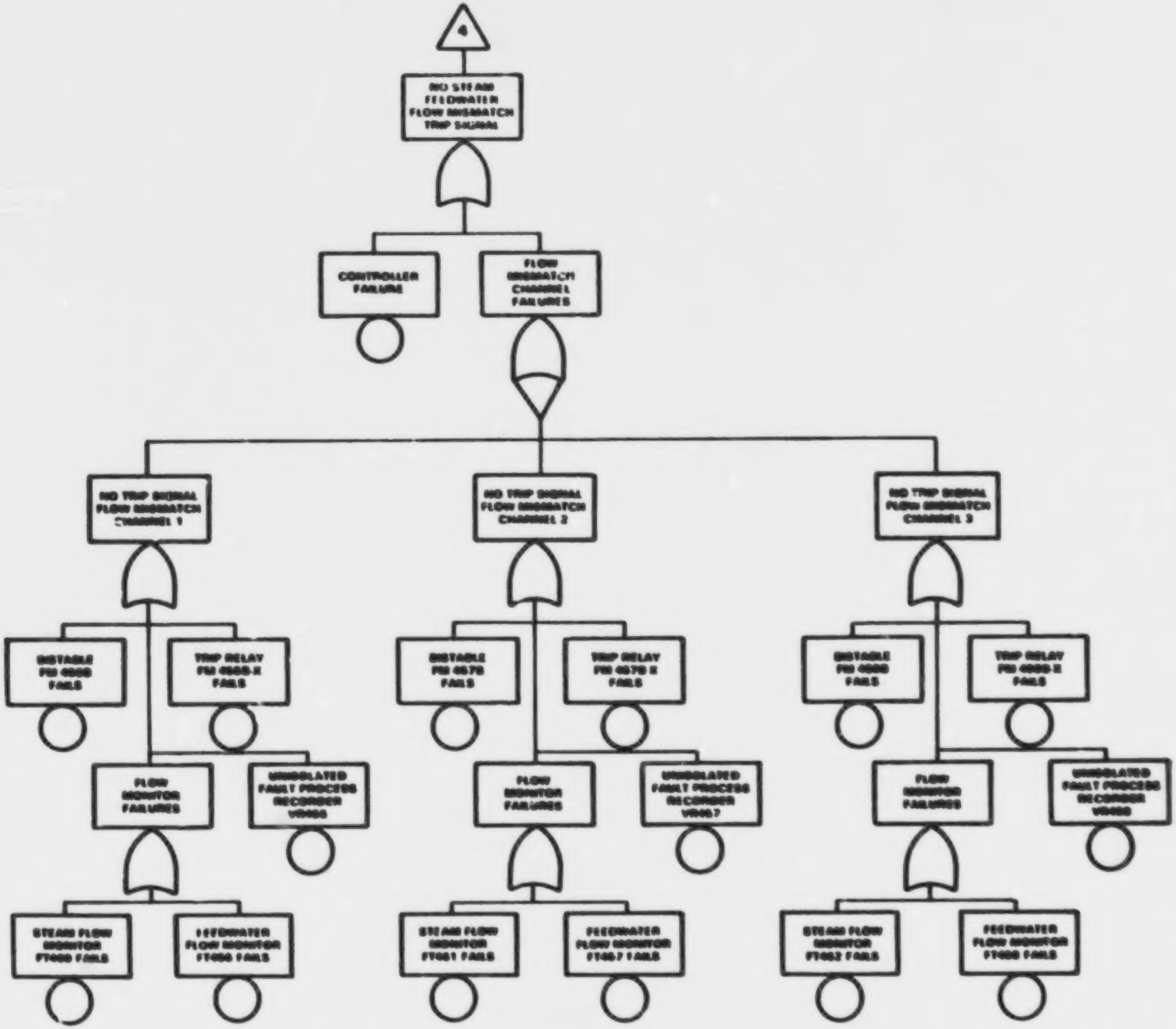
4
NO STEAM FEEDWATER FLOW MISMATCH TRIP SIGNAL
CONTROLLER FAILURE
FLOW MISMATCH CHANNEL FAILURES
NO TRIP SIGNAL FLOW MISMATCH CHANNEL 1
NO TRIP SIGNAL FLOW MISMATCH CHANNEL 2
NO TRIP SIGNAL FLOW MISMATCH CHANNEL 3
BISTABLE FM 456B FAILS
TRIP RELAY FM 456B-X FAILS
BISTABLE FM 457B FAILS
TRIP RELAY FM 457B X FAILS
BISTABLE FM 458B FAILS
TRIP RELAY FM 458B-X FAILS
FLOW MONITOR FAILURES
UNISOLATED FAULT PROCESS RECORDER VR456
FLOW MONITOR FAILURES
UNISOLATED FAULT PROCESS RECORDER VR457
FLOW MONITOR FAILURES
UNISOLATED FAULT PROCESS RECORDER VR458
STEAM FLOW MONITOR FT460 FAILS
FEEDWATER FLOW MONITOR FT456 FAILS
STEAM FLOW MONITOR FT461 FAILS
FEEDWATER FLOW MONITOR FT457 FAILS
STEAM FLOW MONITOR FT462 FAILS
FEEDWATER FLOW MONITOR FT458 FAILS

Figure VII-1.A-1. (CONTINUED)

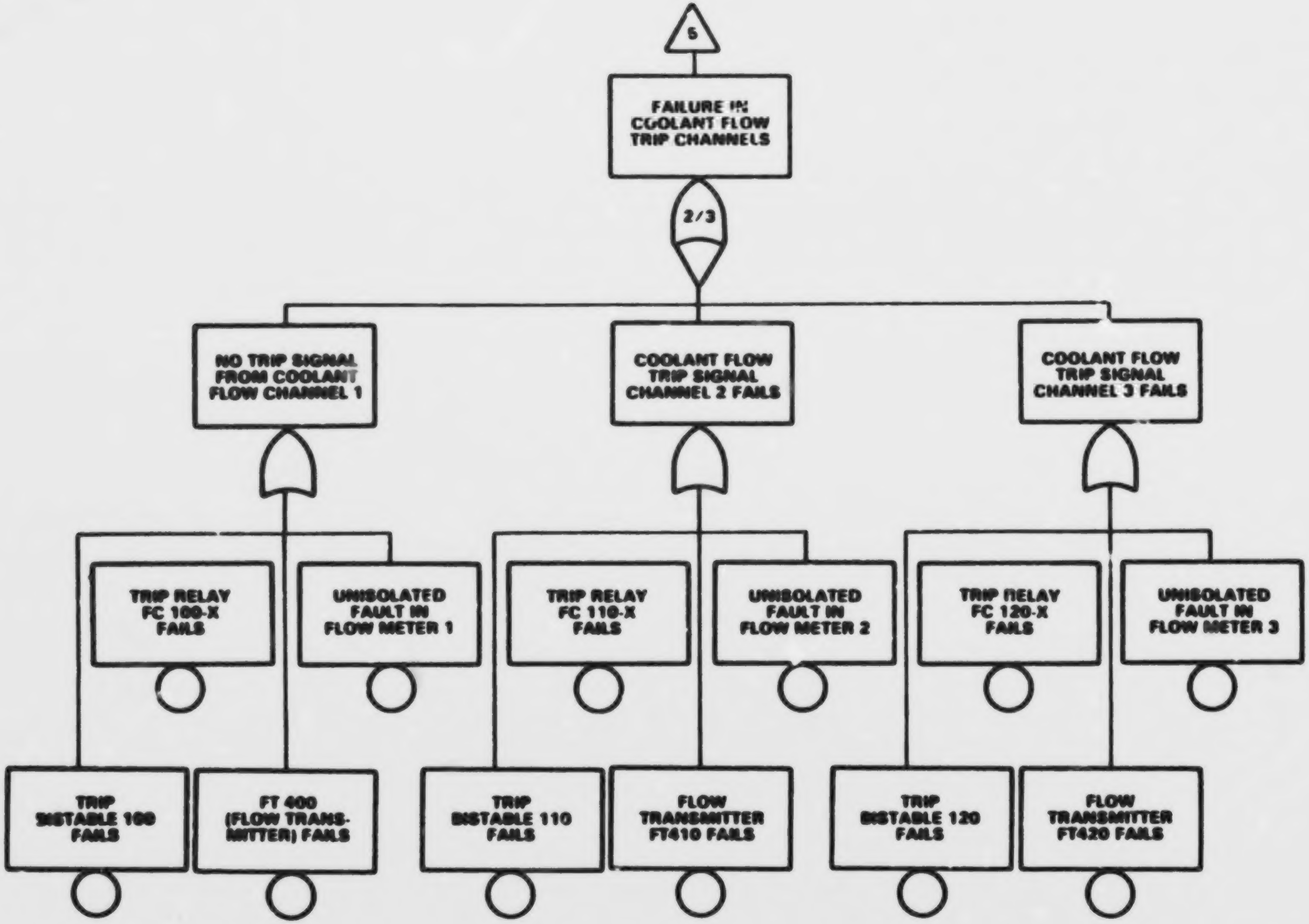
5
FAILURE IN COOLANT FLOW TRIP CHANNELS
2/3
NO TRIP SIGNAL FROM COOLANT FLOW CHANNEL 1
COOLANT FLOW TRIP SIGNAL CHANNEL 2 FAILS
COOLANT FLOW TRIP SIGNAL CHANNEL 3 FAILS
TRIP RELAY FC 100-X FAILS
UNISOLATED FAULT IN FLOW METER 1
TRIP RELAY FC 110-X FAILS
UNISOLATED FAULT IN FLOW METER 2
TRIP RELAY FC 120-X FAILS
UNISOLATED FAULT IN FLOW METER 3
TRIP BISTABLE 100 FAILS
FT 400 (FLOW TRANSMITTER) FAILS
TRIP BISTABLE 110 FAILS
FLOW TRANSMITTER FT410 FAILS
TRIP BISTABLE 120 FAILS
FLOW TRANSMITTER FT420 FAILS

Figure VII-1.A-1. (CONTINUED)

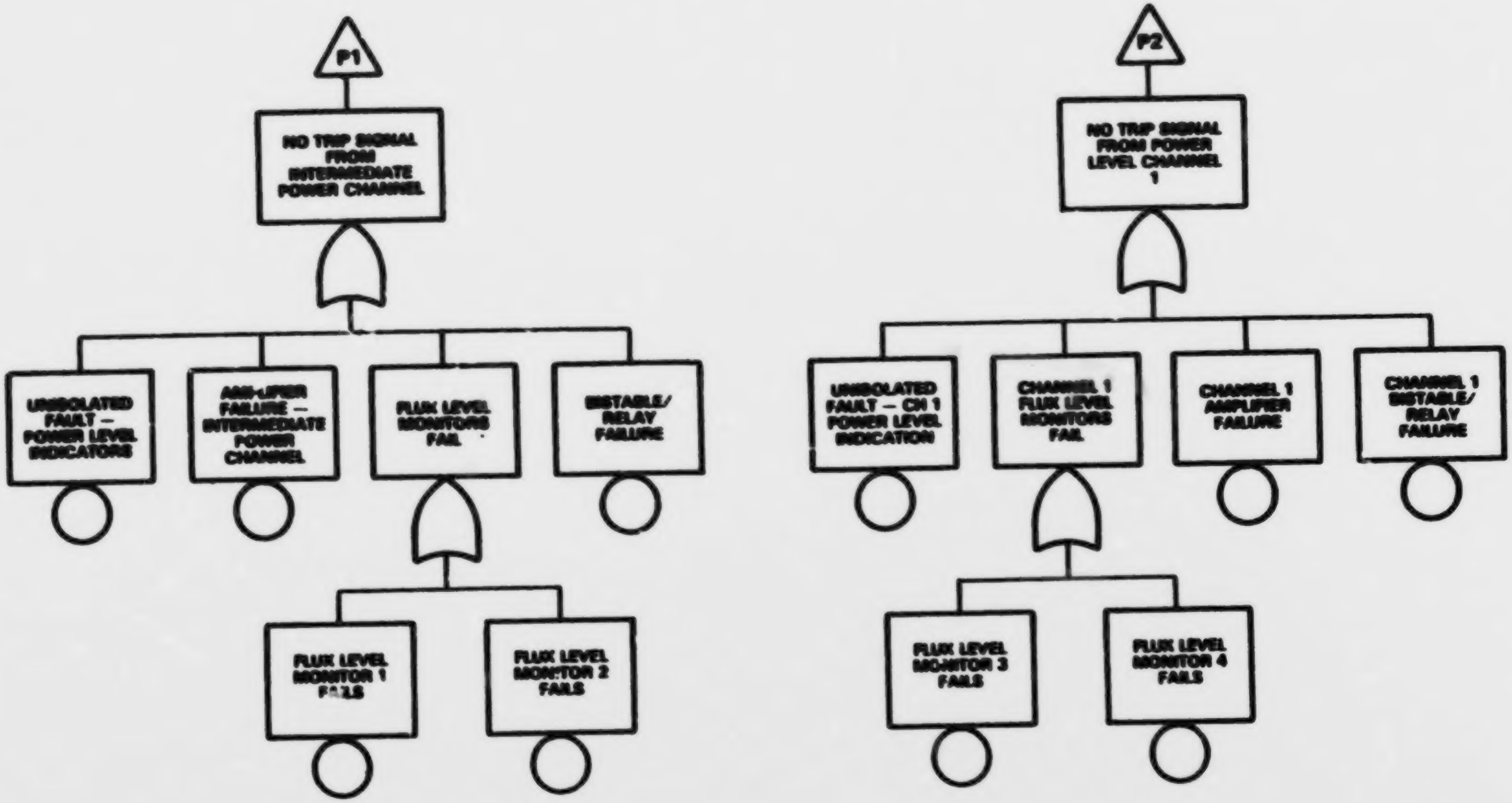
P1
NO TRIP SIGNAL FROM INTERMEDIATE POWER CHANNEL
UNISOLATED FAULT — POWER LEVEL INDICATORS
AMPLIFIER FAILURE — INTERMEDIATE POWER CHANNEL
FLUX LEVEL MONITORS FAIL
BISTABLE/ RELAY FAILURE
FLUX LEVEL MONITOR 1 FAILS
FLUX LEVEL MONITOR 2 FAILS
P2
NO TRIP SIGNAL FROM POWER LEVEL CHANNEL 1
UNISOLATED FAULT — CH 1 POWER LEVEL INDICATION
CHANNEL 1 FLUX LEVEL MONITORS FAIL
CHANNEL 1 AMPLIFIER FAILURE
CHANNEL 1 BISTABLE/ RELAY FAILURE
FLUX LEVEL MONITOR 3 FAILS
FLUX LEVEL MONITOR 4 FAILS

Figure VII-1.A-1. (CONTINUED)

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VII-2 Engineered Safety Features (ESF) System Control Logic and Design

1. NRC Evaluation

Non-safety systems that receive signals from safety systems, for example, the RPS and ESF, must be adequately isolated from the safety systems. Non-safety circuits receiving signals from ESF sensor current loops are required to have isolation devices to ensure electrical independence of the ESF channels. Two of the signals generatd by the ESF may not be properly isolated from the non-safety systems at San Onofre 1. These signals are the containment isolation signal and the safety injection signal.

2. NRC Recommendation

The licensee should demonstrate that the isolation devices currently in use between the input signal channels and the safeguard load sequencing system (safety injection signal), containment spray and the containment isolation system are adequate. If this can not be done the isolators should be replaced with acceptably qualified isolators.

3. Systems Affected

The systems affected by this issue include the safety injection system, containment spray system, and the containment isolation system.

4. Comments

Two of the three signals affected by this issue will not be analyzed here. The containment spray signal as evaluated in the technical evaluation report by EG&G Idaho, Inc. was found to have adequate isolators between it and non-safety systems. The containment isolation system is isolated from non-safety systems by the use of relays and relay contacts. This type of isolation has been determined to be acceptable.

Therefore, only the safety injection signal will be analyzed in this report. Qualification of the existing isolators is beyond the scope of this analysis. The assumption is made that the isolators currently in use do not adequately protect the safety injection signal from faults in non-safety

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systems. For this reason the results of this analysis should be used only to determine whether the isolators' qualifications should be evaluated. Only after it has been determined that the isolators are indeed inadequate, i.e., they do not provide the required protection, should they be replaced.

5. Analysis

The signal of interest for the safety injection signal is the pressurizer pressure signal. This signal is not properly isolated from the 3 pen recorder that can be connected to any one of the three pressurizer pressure channels. Also each pressurizer pressure channel outputs a signal to a pressure indicating meter. This meter is not properly isolated from the safety system. (The safety injection signal is generated from the same sensors that produce a trip signal. These unisolated components are the same components for which an analysis was performed for Topic VII-1.A) Before the pressurizer pressure signal is transmitted to the safety injection system logic it passes through an input buffer module. This is the isolation device presently in use at the San Onofre 1 plant.

The pressurizer pressure signals are input into both subchannels of the two load sequencers. The output from each pressurizer pressure transmitter goes to two bistables. One bistable transmits to sequencer train A, the second to sequencer train B. The outputs of the three bistables in one sequencer train are arranged in two two-out-of-three logic matrices, one each for the two subchannels for the sequencer. (Figure VII-2-1 is a logic diagram for the pressurizer pressure signal for the safety injection system.) The input buffer modules are located between the bistables and the two-of-three logic matrices.

For this analysis it is assumed that an unisolated fault in the non-safety system could propogate through the bistables and the safety injection system logic. With this assumption an unisolated fault could fail the safety injection system. There are three meters and one recorder attached to the pressurizer pressure sensors that are not isolated. Using the data developed for Topic VII-1.A the unavailabilities of these indicators are 7.7E-4 for the meters and 1.1E-3 for the recorder. The unavailability of the safety injection signal due to these faults would be the sum of the unavailabilities, 3.4E-3.

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The safety injection signal system for nuclear plants with similar safety injection signals (i.e., pressurizer pressure and containment pressure arranged in a 2 out of 3 matrix with two sequencer trains each with 2 subchannel inputs) generally has a failure probability on the order of 10^{-3}. The contribution of the non-isolated faults is of this magnitude and even slightly larger than the normal system failure probability.

If the input buffer modules supply adequate isolation, or are replaced with adequate isolators, then the unisolated faults in the recorder and meters would affect only the pressurizer pressure signal. Failure of the indicating meter on each sensor channel would affect only that sensor channel and the failure of the recorder would affect only the pressurizer pressure signal and not the containment pressure signal. The availability of a second initiation signal would significantly reduce the effect of faults in the non safety systems that could affect the pressurizer pressure signal.

With the bistable outputs properly isolated the failure probability of the pressurizer presure signal alone is 1.1E-3, due primarily to the failure of the recorder failing all three pressurizer pressure sensor channels. A simplified fault tree for the pressurizer pressure signals is shown in Figure VII-2-2. The data used is the data developed in Topic VII-1.A. For the safety injection signal to fail the containment pressure signal must fail in addition to the pressurizer pressure signal. With the effects of faults in the pressurizer pressure signal limited to that signal the failure probability of the San Onofre 1 safety injection signal can be expected to be of approximately the same value as in other nuclear plants with similar systems, i.e., 10^{-4} to 10^{-3}.

6. Conclusion

Under the constraints imposed by the assumptions made for this analysis this issue would be rated to be of high risk significance. After completion of this analysis, the licensee demonstrated that sufficient isolation exists between the safety and non-safety grade systems. Thus, this issue is completely resolved.

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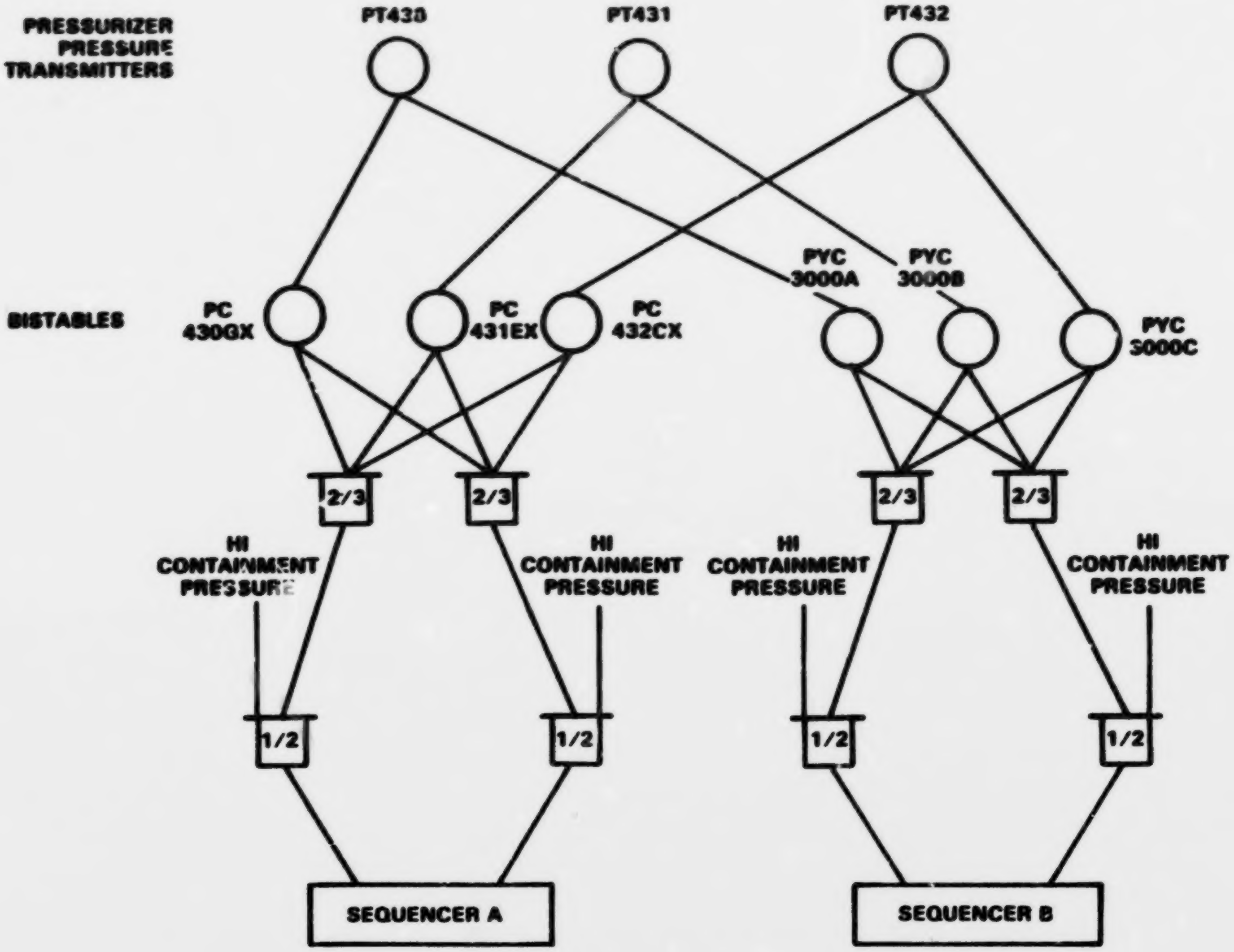
PRESSURIZER
PRESSURE
TRANSMITTERS
PT430
PT431
PT432
BISTABLES
PC
430GX
PC
431EX
PC
432CX
PYC
3000A
PYC
3000B
PYC
3000C
2/3
2/3
2/3
2/3
HI
CONTAINMENT
PRESSURE
HI
CONTAINMENT
PRESSURE
HI
CONTAINMENT
PRESSURE
HI
CONTAINMENT
PRESSURE
1/2
1/2
1/2
1/2
SEQUENCER A
SEQUENCER B

Figure VII-2-1. SIS — PRESSURIZER PRESSURE SIGNAL LOGIC

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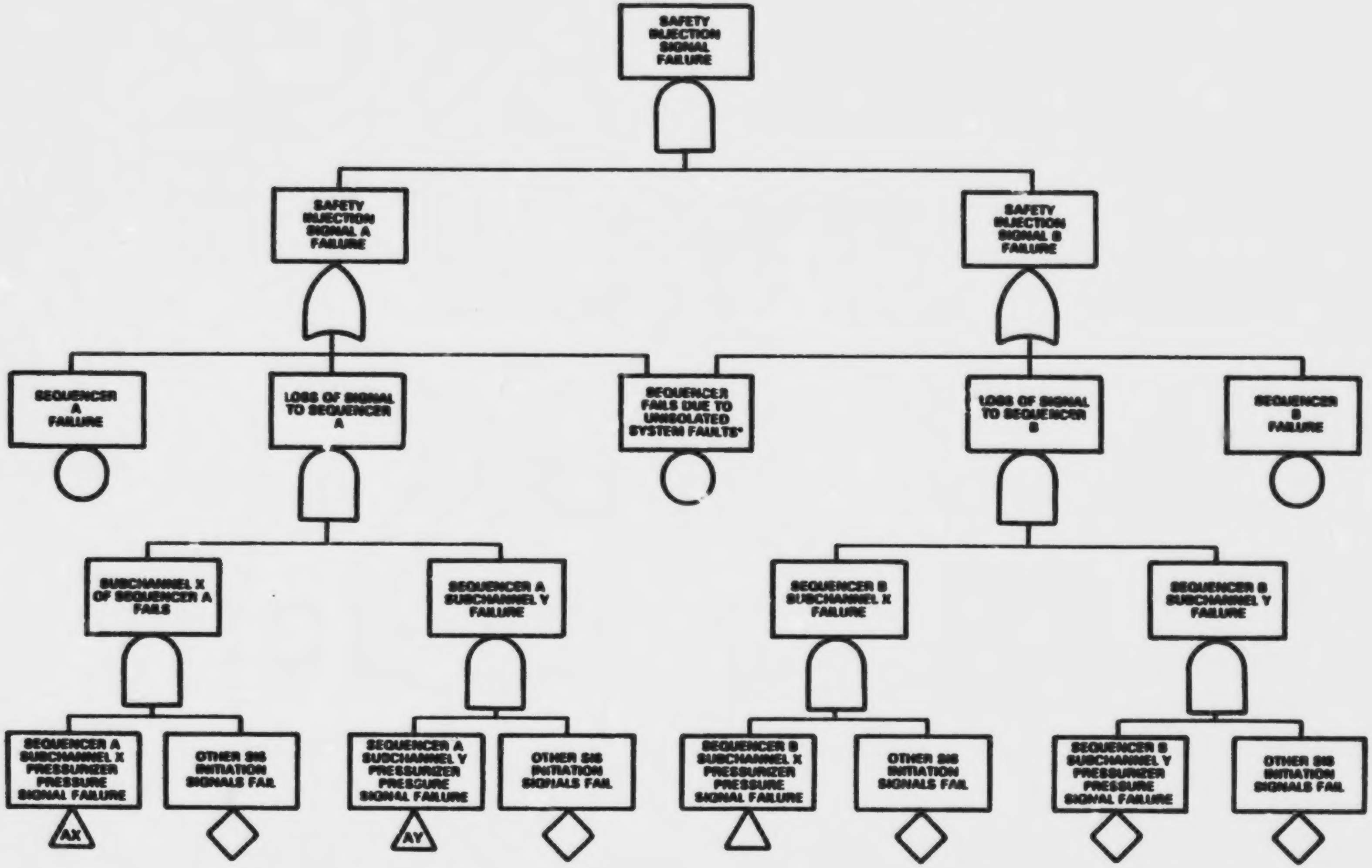
SAFETY INJECTION SIGNAL FAILURE
SAFETY INJECTION SIGNAL A FAILURE
SAFETY INJECTION SIGNAL B FAILURE
SEQUENCER A FAILURE
LOSS OF SIGNAL TO SEQUENCER A
SEQUENCER FAILS DUE TO UNISOLATED SYSTEM FAULTS*
LOSS OF SIGNAL TO SEQUENCER B
SEQUENCER B FAILURE
SUBCHANNEL X OF SEQUENCER A FAILS
SEQUENCER A SUBCHANNEL Y FAILURE
SEQUENCER B SUBCHANNEL X FAILURE
SEQUENCER B SUBCHANNEL Y FAILURE
SEQUENCER A SUBCHANNEL X PRESSURIZER PRESSURE SIGNAL FAILURE
OTHER SIS INITIATION SIGNALS FAIL
SEQUENCER A SUBCHANNEL Y PRESSURIZER PRESSURE SIGNAL FAILURE
OTHER SIS INITIATION SIGNALS FAIL
SEQUENCER B SUBCHANNEL X PRESSURIZER PRESSURE SIGNAL FAILURE
OTHER SIS INITIATION SIGNALS FAIL
SEQUENCER B SUBCHANNEL Y PRESSURIZER PRESSURE SIGNAL FAILURE
OTHER SIS INITIATION SIGNALS FAIL
AX
AY

Figure VII-2-2. FAULT TREE FOR FAILURE OF SIS DUE TO PRESSURIZER PRESSURE SIGNAL FAULTS*

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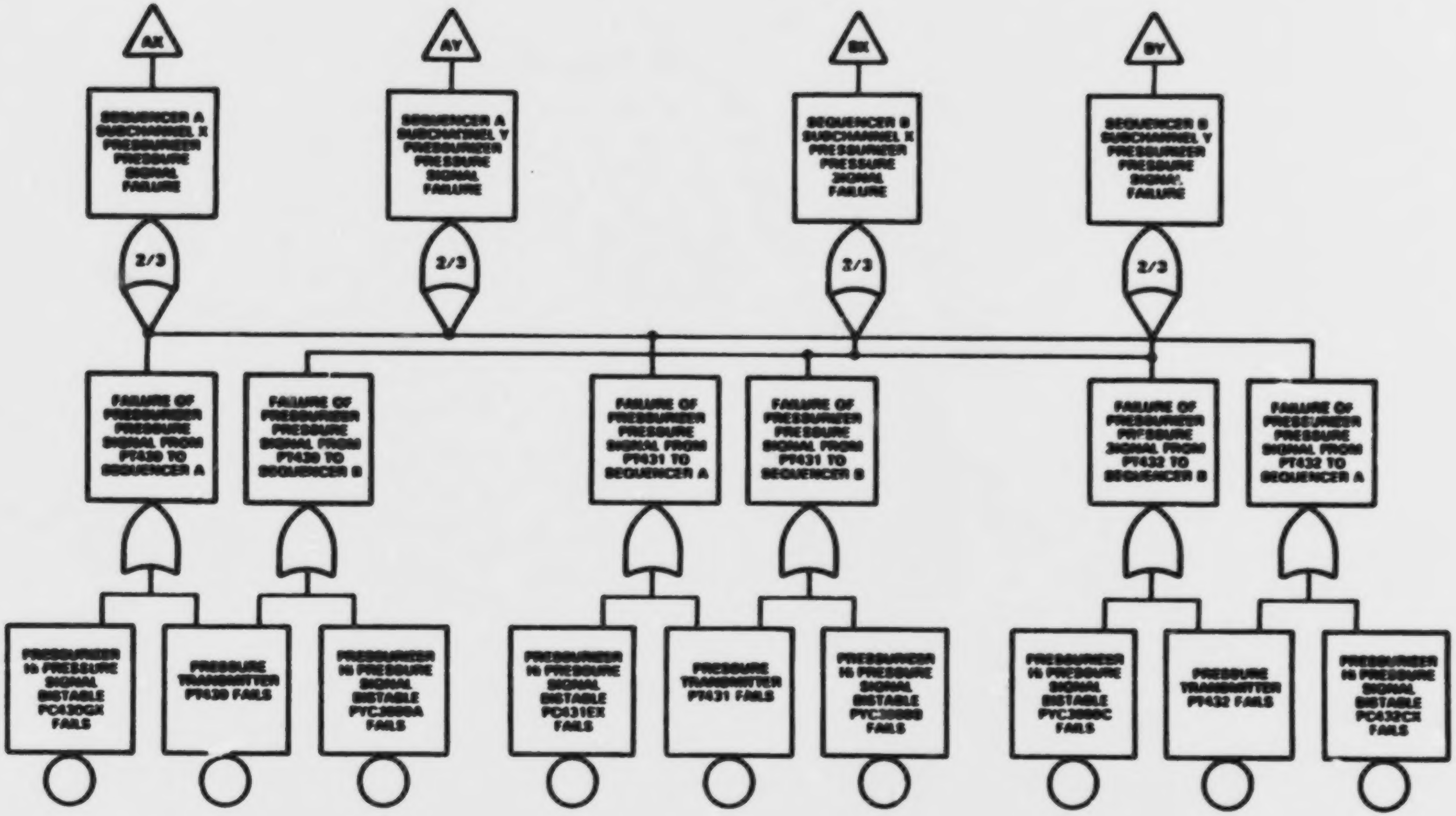
AX
AY
BX
BY
SEQUENCER A SUBCHANNEL X PRESSURIZER PRESSURE SIGNAL FAILURE
SEQUENCER A SUBCHANNEL Y PRESSURIZER PRESSURE SIGNAL FAILURE
SEQUENCER B SUBCHANNEL X PRESSURIZER PRESSURE SIGNAL FAILURE
SEQUENCER B SUBCHANNEL Y PRESSURIZER PRESSURE SIGNAL FAILURE
2/3
2/3
2/3
2/3
FAILURE OF PRESSURIZER PRESSURE SIGNAL FROM PT430 TO SEQUENCER A
FAILURE OF PRESSURIZER PRESSURE SIGNAL FROM PT430 TO SEQUENCER B
FAILURE OF PRESSURIZER PRESSURE SIGNAL FROM PT431 TO SEQUENCER A
FAILURE OF PRESSURIZER PRESSURE SIGNAL FROM PT431 TO SEQUENCER B
FAILURE OF PRESSURIZER PRESSURE SIGNAL FROM PT432 TO SEQUENCER B
FAILURE OF PRESSURIZER PRESSURE SIGNAL FROM PT432 TO SEQUENCER A
PRESSURIZER Hi PRESSURE SIGNAL BISTABLE PC430GX FAILS
PRESSURE TRANSMITTER PT430 FAILS
PRESSURIZER Hi PRESSURE SIGNAL BISTABLE PYC3000A FAILS
PRESSURIZER Hi PRESSURE SIGNAL BISTABLE PC431EX FAILS
PRESSURE TRANSMITTER PT431 FAILS
PRESSURIZER Hi PRESSURE SIGNAL BISTABLE PYC3000B FAILS
PRESSURIZER Hi PRESSURE SIGNAL BISTABLE PYC3000C FAILS
PRESSURE TRANSMITTER PT432 FAILS
PRESSURIZER Hi PRESSURE SIGNAL BISTABLE PC432CX FAILS

Figure VII-2-2. (CONTINUED)

VII-3 Systems Required For Safe Shutdown

1. NRC Evaluation

The only issue under this topic is the lack of redundancy in the Component Cooling Water System (CCWS) surge tank level indicator. Given a leakage in the system, a single failure of the low-level instrumentation can result in depletion of water and failure of the CCWS.

2. NRC Recommendation

A redundant, Class 1E surge tank level instrument must be added to the system.

3. Systems Affected

The Component Cooling Water System and all the systems that are dependent on CCWS for heat removal are affected by this topic.

4. Comments

None.

5. Analysis

The water level in the CCWS is currently monitored by a level indicator which is connected to an alarm in the control room. A low or high water level in the CCWS will set off the alarm. In addition there is a visual gauge where the water level is checked once every shift. If the water level is low in the CCWS surge tank, the operator can manually initiate addition of water to the tank. The concern in this case is that given a leakage in the system, if the low water level in the surge tank is not detected the CCWS pumps can be cavitated resulting in the failure of CCWS. This would effect the performance of many systems that are dependent on CCWS for heat removal. Among these lack of cooling of the main coolant pump seals could result in the failure of the seals and initiation of a small-small LOCA.

Figure VII-3-1 shows a simple fault tree for the event "Cavitation of CCWS Pumps Due to a Leakage." To evaluate the frequency of this event, the probability of various basic events shown on the fault tree must be determined. Since there is not much data on the probability of occurrence of different leakage rates this probability must be estimated. It is known that the probability of a small-small LOCA (pipe break with equivalent diameter of 1/2 to 2 inches) is 1.0×10^{-3} per year (WASH-1400). Thus, the probability of a small leakage must be higher than this. Also, the probability of a pump seal leakage is in the order of 2.0×10^{-2} per year. Based on these numbers a conservative probability of small leakage of 0.1 per year will be used for this analysis.

The CCWS surge tank level indicator is tested every six months. Using a level indicator failure rate of 5.1×10^{-6} (IEEE-Std. 500) and an exposure time of 2160 hours, the unavailability of the level indicator is 1.1×10^{-2}. The probability of failure of the operator to respond to an alarm is 1.0×10^{-4} (NUREG/CR-1278, Table 20-3). For the visual checking of the gauge every shift, it is assumed that a simple checklist exists for performance of this task as a part of many other checks. The probability of failure to detect a low water level is conservatively assumed to be 0.1 per check (NUREG/CR-1278, Table 20-a). It is further assumed that the leakage in the system can be high enough that during one shift the water level can get below the low level alarm. This implies that only one visual shift failure combined with the failure of the level indicator is sufficient to result in depletion of the water in the CCWS surge tank. Based on all above assumptions, the probability of cavitation of CCWS pumps due to leakage is calculated to be 1.1×10^{-4} per year.

6. Conclusion

The probability of failure of the CCWS due to a leakage and failure to detect low water level in the CCWS surge tank is conservatively calculated to be 1.1×10^{-4} per year. This failure among other things could result in failure of the main coolant pump seals and initiation of a small-small LOCA. The probability of this event is one order of magnitude smaller than the overall probability of initiation of a small-small LOCA of 1.0×10^{-3}. Considering all the conservatism involved in this analysis and small contribution of this event to the initiation of a small-small LOCA which

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itself partially contributes to the overall core melt probability, the significance of this issue is ranked low from risk point of view.

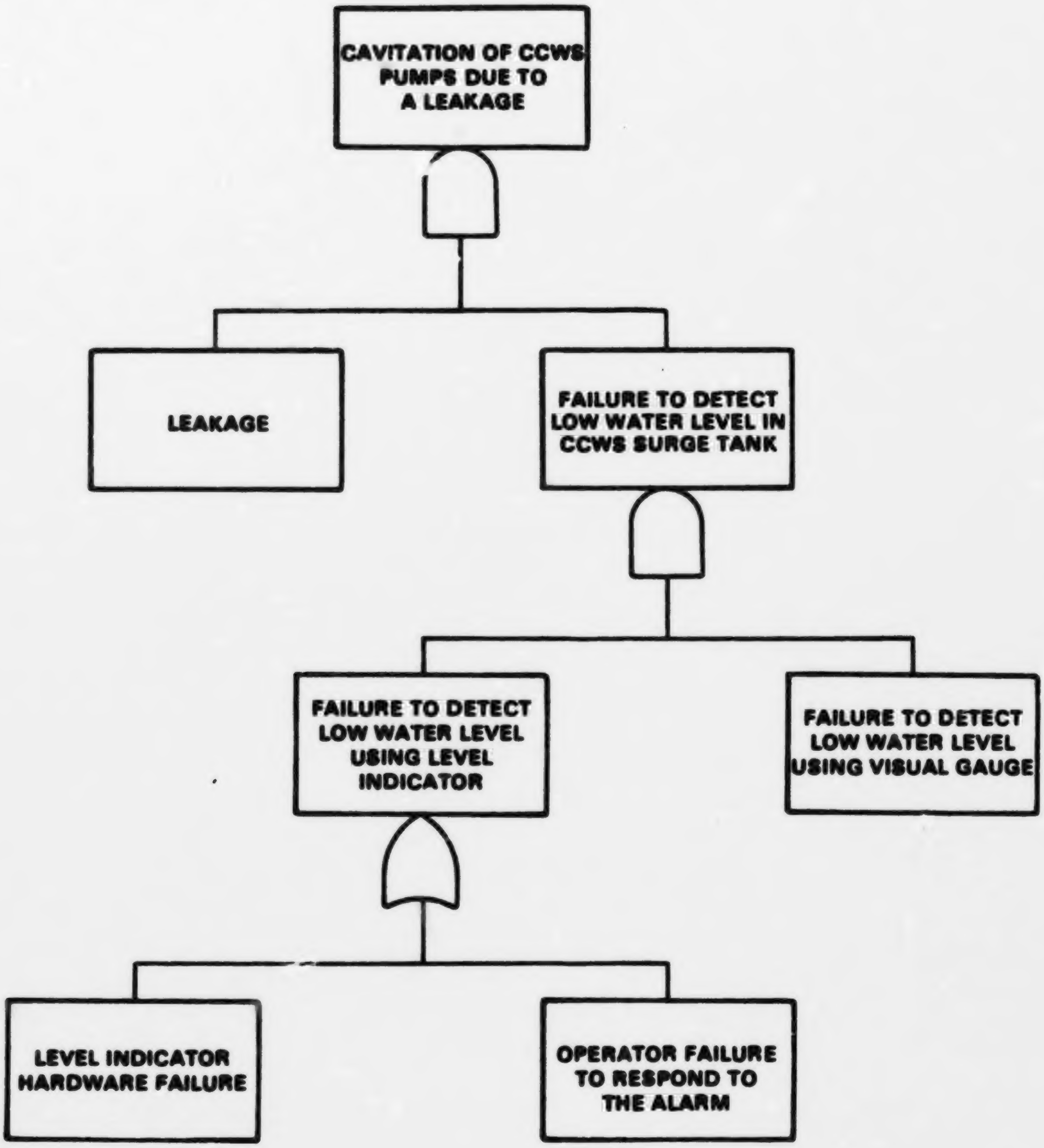
CAVITATION OF CCWS PUMPS DUE TO A LEAKAGE
LEAKAGE
FAILURE TO DETECT LOW WATER LEVEL IN CCWS SURGE TANK
FAILURE TO DETECT LOW WATER LEVEL USING LEVEL INDICATOR
FAILURE TO DETECT LOW WATER LEVEL USING VISUAL GAUGE
LEVEL INDICATOR HARDWARE FAILURE
OPERATOR FAILURE TO RESPOND TO THE ALARM

Figure VII-3-1. FAULT TREE FOR THE EVENT "CAVITATION OF CCWS PUMPS DUE TO A LEAKAGE"

VIII-3.B DC Power System Bus Voltage Monitoring and Annunciation

1. NRC Evaluation

The control room annunciators and monitors for the DC power system of a nuclear power plant should provide the operator with adequate information regarding the status of the DC power system. The information provided in the control room should allow the operator to a) prevent the loss of a DC bus and b) take timely corrective action in the event of a loss of an emergency DC bus. The 125V DC system control room annunciators at San Onofre 1 consist of bus undervoltage, bus ground, charger trouble and battery breaker trip alarms. The control room indication for the uninterruptable power supply (UPS) consists of a system failure alarm.

The control room indications lacking at San Onofre 1 include:

battery current
charger output current
bus voltage
charger output voltage
battery high discharge rate
bus undervoltage (UPS only)
bus overvoltage (UPS only)
bus ground (UPS only)
battery breaker status (UPS only)
charger output breaker status.

2. NRC Recommendation

The SEP staff has recommended that as a minimum six control room indications and alarms be added to the San Onofre 1 plant. These indications and alarms are

Battery current (ammeter charge/discharge)
Battery charger output current (ammeter)
DC bus voltage (voltmeter)

DC bus ground alarm (for ungrounded systems)
Battery breaker or fuse open alarm
Battery charger output breaker or fuse open alarm

3. Systems Affected

The DC power system and the UPS are the only systems directly affected by this issue.

4. Comments

This analysis is based in part on the results of NUREG-0666, "A Probabilistic Safety Analysis of DC Power Supply Requirements for Nuclear Power Plants." The analysis of detectable versus nondetectable battery faults is based on the NUREG-0666 analysis. Data not taken from NUREG-0666 is generic plant data.

The UPS supplies power to MOV 850C, one of the three safety injection valves. It is not required to supply power to any other component. Its charger receives power from MCC 3. The remaining two safety injection valves are powered from MCC 1 and MCC 2.

5. Analysis

A fault tree for the UPS is presented in Figure VIII-3.B-1. The modifications proposed for the system annunciation will affect the battery unavailabilities and the detection intervals for the faults in the rest of the system. With the proper annunciation devices faults in the system will be detected immediately. Only half of the battery faults can be expected to be detected by the improved annunciation system. This is based on the results of NUREG-0666. In this report an evaluation of plant LERs showed that even in plants with the required annunciation systems half of the battery faults were not detected until battery tests. The assumption is made that with the present system annunciation all faults are not detected until system tests. For this system the tests are performed every 18 months, at refueling.

The UPS supplies power to MOV 850C (a safety injection valve) and to no other components. Therefore it is possible to not only evaluate the effect of improved annunciation on the UPS but also on the safety injection system. The data used to evaluate the system is presented in Table VIII-3.B-1. Using this data and the fault tree in Figure VIII-3.B-1 the UPS unavailabilities, for the system with the present annunciation devices, is 3.2E-4. With the modified annunciation this unavailability is reduced to approximately 1E-6.

The UPS powers only one of three safety injection valves all three of which must fail to open to fail the safety injection system. These valves are tested during refueling outages. The probability of an MOV failing to open can be calculated as

$$1/2\ \lambda T$$

where

λ = valve failure rate = 2.8E-6/hr
(from WASH-1400)
T = test interval = 13140 hrs.

For these valves the failure probability is 1.8E-2. The failure of the UPS affects only one of the three valves, and only increases the valve failure probability by 3E-4, less than a 2% increase. This is an insignificant increase in the failure probability of one valve.

There are three sources of power for each of the 125V DC system trains. Both 125V DC system buses are powered by a battery and two battery chargers. For each bus one battery charger is powered through a bus connected to diesel generator #1. The other battery charger can receive power from diesel generator #2. During a loss of offsite power both 125V DC buses can be powered by either one of the diesel generators. A fault tree for each of the 125V DC buses is shown in Figure VIII-3.B-2.

As in the analysis for the UPS it has been assumed that any faulted condition that is not annunciated will not be detected until the battery tests at refueling, approximately every 18 months. Data for this analysis is presented in Table VIII-3.B-2.

The unavailabilities of a single 125V DC bus with the present annunciators are 4.1E-4 with a loss of offsite power and 5E-6 with no loss of offsite power. With the proposed annunciator modifications these unavailabilities are reduced to 1.1E-4 and 1E-6, respectively. The reduction for the case involving a loss of offsite power is 3E-4, a reduction by a factor of 4.

6. Conclusion

The proposed annunciator modifications reduce the battery system unavailabilities for both the 125V DC system and for the UPS. The reduction of the UPS unavailability is not significant since the UPS supplies power to only one component, a safety injection system valve, whose failure is dominated by mechanical valve failures. The failure of the UPS does not significantly affect the valve failure probability. Failure of the 125V DC system affects several systems. Therefore the proposed modifications would probably have a significant effect on the core melt frequency. However, the failure probability of a 125V DC bus as calculated for San Onofre 1 is less than that calculated for the risk based analysis for previous SEP plants. (See for example the Risk Based Categorization of Haddam Neck SEP Issues, SAI-83-128-WA.) This is primarily due to the arrangement of the DC power supplies. Both buses can be powered from three sources; the battery and both diesel generators. Based on the results of the analysis of the 125V DC system we rank this issue to be of medium risk significance.

Table VIII-3.B-1
UPS Data Summary

	Failure Rate (hrs^{-1})	Fault Exposure Time (hrs)	Unavailability
Switchboard - Local Faults			~10^{-6}
Switchboard - Test/Maintenance			~10^{-7}
NO AC to Battery Charger[1]			
LOSP			3E-2
No LOSP			~10^{-6}
Battery Charger - Local Faults			
"As is"	2.8E-6	6570[2]	1.8E-2
"Mod"	2.8E-6	1[3]	2.8E-6
Battery Charger Breaker - Fails Open			
"As is"	1E-6	6570	6.6E-3
"Mod"	1E-6	1	1E-6
Battery Breaker - Fails Open			
"As is"	1E-6	6570	6.6E-3
"Mod"	1E-6	1	1E-6
Detectable Battery Faults			
"As is"	0	-	-
"Mod"	5E-7	1	5E-7
NonDetectable Battery Faults			
"As is"	1E-6	6570	6.6E-3
"Mod"	5E-7	6570	3.3E-3

1) for a loss of offsite power (LOSP) unavailability is dominated by a failure of diesel generator to start, for non LOSP unavailability is probability of AC bus fault

2) 6570 hours is 1/2 of 18 months

3) 1 hr - length of demand on system

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Table VIII-3.B-2
125V DC System Failure Data

	Failure Rate (hrs^{-1})	Fault Exposure Time (hrs)	Unavailability
Switchboard - Local Faults			~1E-6
Switchboard - Test/Maintenance			~1E-6
Diesel Generator Failure to Start	3E-2/d		3E-2
LOSP			1 or 0
Battery Charger - Local Fault			
"As is Annunciation"	2.8E-6	6570	1.8E-2
"Modified Annunciation"	2.8E-6	1	2.8E-6
Battery Charger Breaker - Fails Open			
"As is Annunciation"	1E-6	6570	6.6E-3
"Modified Annunciation"	1E-6	1	1E-6
Detectable Battery Faults			
"As is Annunciation"	0	-	-
"Modified Annunciation"	5E-7	1	5E-7
NonDetectable Battery Faults			
"As is Annunciation"	1E-6	6570	6.6E-3
"Modified Annunciation"	5E-7	6570	3.3E-3
Battery Breaker - Fails Open	1E-6	1	1E-6

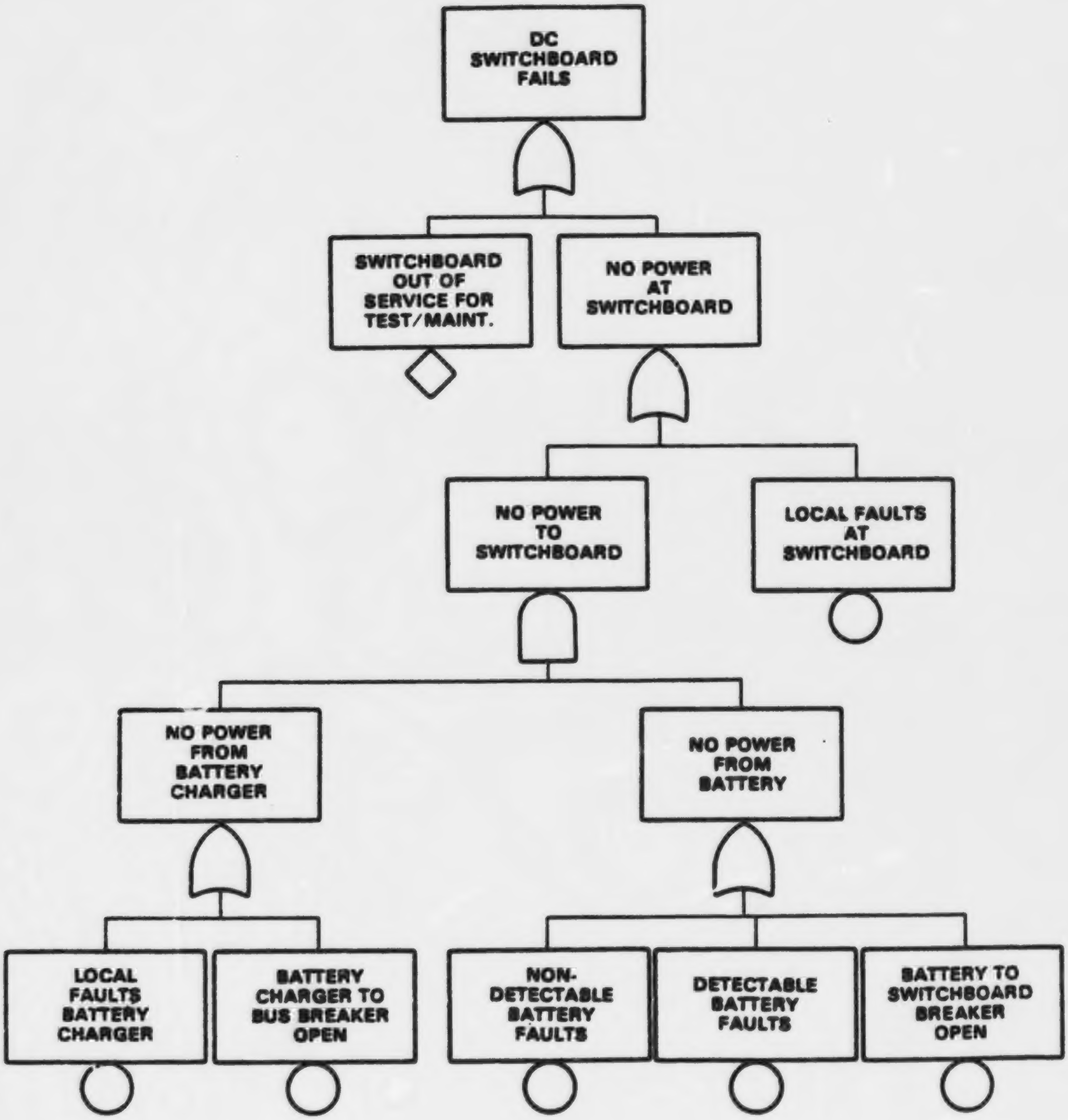
DC SWITCHBOARD FAILS
SWITCHBOARD OUT OF SERVICE FOR TEST/MAINT.
NO POWER AT SWITCHBOARD
NO POWER TO SWITCHBOARD
LOCAL FAULTS AT SWITCHBOARD
NO POWER FROM BATTERY CHARGER
NO POWER FROM BATTERY
LOCAL FAULTS BATTERY CHARGER
BATTERY CHARGER TO BUS BREAKER OPEN
NON-DETECTABLE BATTERY FAULTS
DETECTABLE BATTERY FAULTS
BATTERY TO SWITCHBOARD BREAKER OPEN

Figure VIII-3.B-1. SIMPLIFIED UPS FAULT TREE

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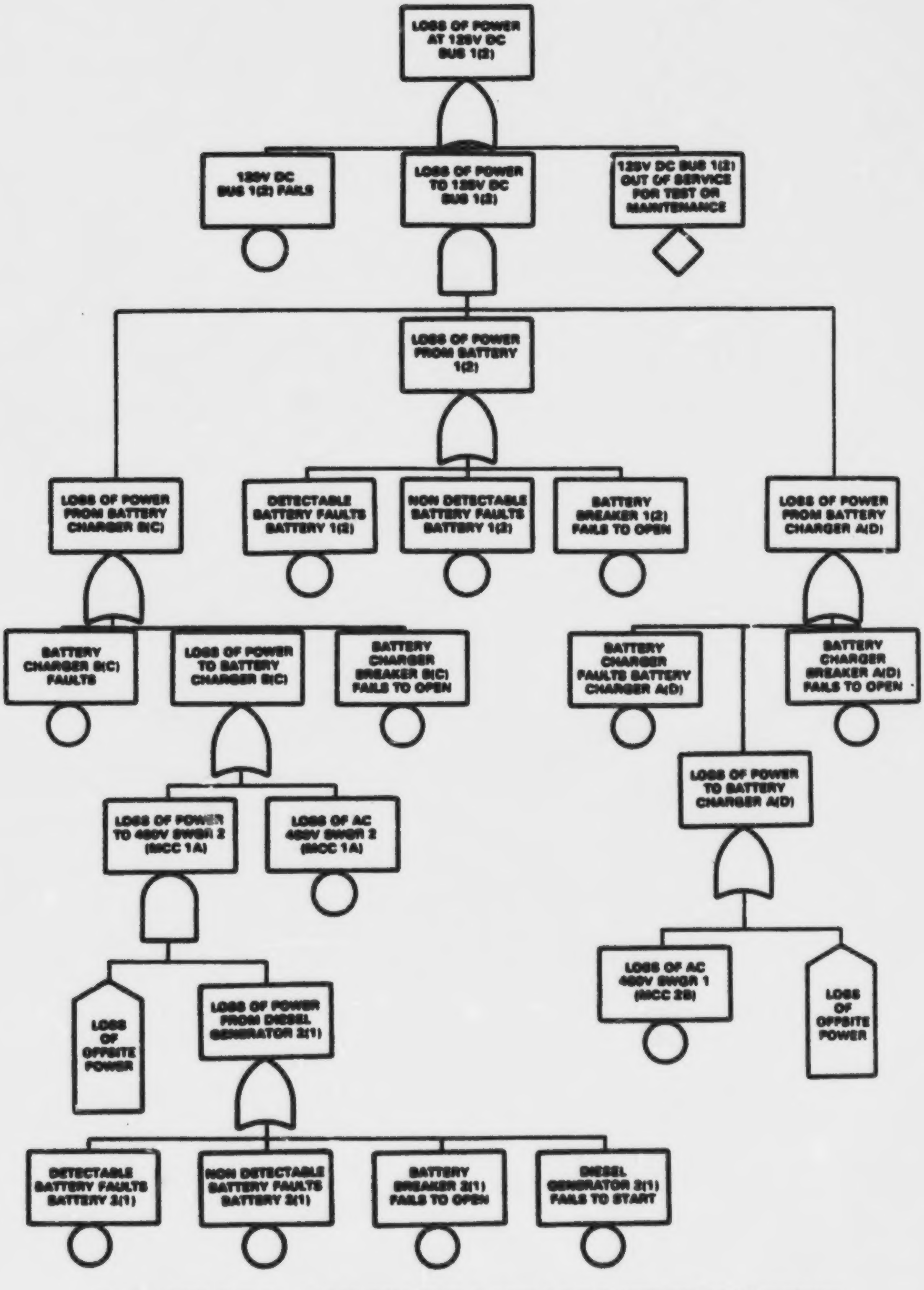
LOSS OF POWER AT 125V DC BUS 1(2)
125V DC BUS 1(2) FAILS
LOSS OF POWER TO 125V DC BUS 1(2)
125V DC BUS 1(2) OUT OF SERVICE FOR TEST OR MAINTENANCE
LOSS OF POWER FROM BATTERY 1(2)
LOSS OF POWER FROM BATTERY CHARGER B(C)
DETECTABLE BATTERY FAULTS BATTERY 1(2)
NON DETECTABLE BATTERY FAULTS BATTERY 1(2)
BATTERY BREAKER 1(2) FAILS TO OPEN
LOSS OF POWER FROM BATTERY CHARGER A(D)
BATTERY CHARGER B(C) FAULTS
LOSS OF POWER TO BATTERY CHARGER B(C)
BATTERY CHARGER BREAKER B(C) FAILS TO OPEN
BATTERY CHARGER FAULTS BATTERY CHARGER A(D)
BATTERY CHARGER BREAKER A(D) FAILS TO OPEN
LOSS OF POWER TO BATTERY CHARGER A(D)
LOSS OF POWER TO 480V SWGR 2 (MCC 1A)
LOSS OF AC 480V SWGR 2 (MCC 1A)
LOSS OF AC 480V SWGR 1 (MCC 2B)
LOSS OF OFFSITE POWER
LOSS OF POWER FROM DIESEL GENERATOR 2(1)
LOSS OF OFFSITE POWER
DETECTABLE BATTERY FAULTS BATTERY 2(1)
NON DETECTABLE BATTERY FAULTS BATTERY 2(1)
BATTERY BREAKER 2(1) FAILS TO OPEN
DIESEL GENERATOR 2(1) FAILS TO START

Figure VIII-3.B-2. SAN ONOFRE 1 125V DC SYSTEM FAULT TREE

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VIII-4 Electrical Penetrations of Reactor Containment

1. NRC Evaluation

Adequate protection for the following electrical penetrations does not exist at San Onofre:

> The DC penetration (EPC-6) does not meet current requirements of RG 1.63 and IEEE Std 317 for any short circuit conditions with a failure of the primary breaker.

Current criteria requires that for each penetration, protective systems should provide primary and secondary protection devices to prevent a single failure in conjunction with a circuit overload from impairing containment integrity. These requirements were developed to prevent a single failure from allowing excess current in the penetration conductors that could adversely affect penetration seals.

2. NRC Recommendations

The recommendations propose that the design of backup protection for most low voltage (less than 1000V) AC and all DC penetrations at San Onofre be modified to provide adequate, coordinated protection against all postulated faults inside of containment assuming the failure of the primary protection device.

3. Systems Affected

The system affected is the containment isolation system.

4. Comments

In a LOCA environment electrical penetrations may not be capable of maintaining their integrity given a failure of the fault protection devices and the existence of an electrical fault.

5. Analysis

A penetration fault in a LOCA environment requires that two events occur. First an electrical fault (circuit overload) must exist and the breaker (protection device) on that circuit must fail to isolate the circuit. The data used in this analysis is shown in Table VIII-4-1. The failure of an electrical penetration due to a fault would be:

P_1 = (number of cables penetration containment) x
P (electrical component failure) x P (Breaker failure).

For the DC circuits this would be (P_{DC}):

$$D_{DC} = (10)\ (3.6E\text{-}5)\ (1E\text{-}3) = 3.6E\text{-}7$$

For the low voltage AC circuits this would be (P_{AC}):

$$P_{AC} = (20)\ (3.6E\text{-}5)\ (1E\text{-}3) = 7.2E\text{-}7$$

The combined failure probability for these electrical penetrations is (P_{Telec}):

$$P_{Telec} = P_{DC} + P_{AC}$$

$$= 3.6E\text{-}7 + 7.2E\text{-}7$$

$$= 1.08E\text{-}6$$

6. Conclusion

The failure probability of containment integrity due to an electrical penetration not currently meeting the GDC, caused by an overloaded circuit is calculated to be 1.08E-6.

This failure probability is much smaller than the failure of containment isolation due to other causes. Thus the risk significance of this issue is ranked low.

Table VIII-4-2 Failure Data Summary

FAILURE	FAILURE RATE*	FAULT EXPOSURE TIME	UNAVAILABILITY
Solid state device fails shorted	1E-7/hour	360 hours	3.6E-5
Circuit breaker	1E-3/demand		1E-3

*Data taken from WASH-1400

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IX-3 Station Service and Cooling Water Systems

1. NRC Evaluation

Several issues related to the Component Cooling Water System (CCWS) and Salt Water Cooling System (SWCS) were identified by the NRC for this topic. Among these, the following issues are relevant for analysis using PRA techniques. For the component cooling water system, possible passive failures of the system and its importance must be addressed. For the salt water cooling system possibility of failure of tsunami or stop gates and its effect on the SWCS availability under accident conditions must be evaluated.

2. NRC Recommendation

Applicant should analyze various issues of concern and submit the results to the NRC for further evaluation.

3. Systems Affected

Besides component cooling and salt water cooling systems, all other components and systems such as reactor coolant pumps, residual heat removal system, recirculation heat exchangers that are cooled by the component cooling water system are systems affected by this issue.

4. Comments

None

5. Analysis

A simplified schematic of the component cooling water system is shown in Figure IX-3-1. To evaluate the importance of the passive failures, a fault tree for the event "Insufficient Flow To The Auxiliary Coolant System" was developed and is shown in Figure IX-3-2. Note that during normal operation only one CCWS pump and heat exchanger is in service. During cooldown periods where the maximum heat load is imposed on the CCWS, all three pumps and both heat exchangers are used. In this case loss of two pumps and one heat exchanger does not result in failure of the system and only results in lower rate of cooldown. But for the present analysis failure of any pumps or heat exchangers is conservatively assumed to fail the system. The fault tree for the CCWS is next quantified using the data shown in Table IX-3-1 (WASH-1400). With all the conservatism included in the calculation of passive failures consisting of pipe rupture and heat exchanger failure, the total contribution of these failures to the failure of the CCWS is about 6%. Thus, the contribution of the passive failures to the failure of the CCWS is not very significant.

The salt water cooling system circulates water from the intake structure through CCWS heat exchanger to remove the heat transferred to the CCWS. Figure IX-3-3 shows a simplified diagram of this system. The concern in this issue is related to the possibility of failure of the stop gates and complete unavailability of the SWS to remove heat. During normal operation, NRC's evaluation has shown that if the gate valves fail closed there is sufficient time for the operator to correct the situation before water temperature in CCWS and other systems cooled by SWS is too high. But right after a reactor shutdown, whether normal or due to an accident, heat load on SWCS is high and if the gate valves are closed the water inventory in the screenwell will eventually be depleted. If the salt water flow is completely lost there is a short time (in the order of three minutes) before the water temperature in CCWS exceeds the design temperature.

The accident scenario consists of a reactor shutdown followed by failure of tsunami gate valve. Since the refueling at San Onofre is every 18 months the frequency of normal shutdown is less than one. But to this we must add abnormal shutdowns. Thus, a frequency of one shutdown per year is taken to include abnormal scrams. The failure probability of the gate valve is 1.0×10^{-4}/D (WASH-1400). This demand failure probability is based on a monthly test. Thus, the hourly failure rate for the gate valve can be calculated from the relationship:

$$\lambda = \frac{2q}{T}$$

where λ is the hourly failure rate of the gate valve
q is the unavailability of the gate valve per demand
T is the time between two consecutive tests.

From this relationship an hourly failure of 2.7×10^{-7}/hour can be found. Following a reactor shutdown the high heat load on SWCS continues for about 24 hours. After that the heat load is low enough that it would be like normal operation where there is sufficient time for correction of the situation even if the gate valve fails closed. Thus the unavailability of the gate valve during the maximum heat load conditions is 6.4×10^{-6}. This unavailability combined with the shutdown frequency of once per year results in a failure frequency of 6.4×10^{-6}/year for the SWS due to closure of the gate valve. This frequency is considerably lower than failure probability of SWCS due to hardware failure. Additionally, if SWCS is failed for an extended period of time, RHRS can be shut down to reduce the heat load on SWCS. In this case the main coolant will heat up somewhat and the heat can be removed using the main heat exchangers. Thus, the possibility of a serious accident as a result of failure of the tsunami gate valve is negligible.

6. Conclusions

The contribution of passive failures to the total failure probability of the component cooling water system was calculated using a simple fault tree for the system. It was shown that with all the conservative assumption related to the passive failures, their contribution to the total failure of the CCWS is about 6%. This contribution is judged to be insignificant with respect to the overall risk of operation of this reactor.

The importance of failure of tsunami stop gates in the salt water cooling system following a reactor shutdown was also evaluated. The accident scenario consists of simultaneous failure of the tsunami gate valve and a reactor scram. The probability of this event leading to complete unavailability of the SWS is 6.4×10^{-6}. This probability is considerably lower than failure probability of SWCS due to hardware failure. Thus, the contribution of the SWCS unavailability as a result of tsunami gate valve closure to the risk associated with the operation of this plant is judged to be low.

Table IX-3-1 Failure Rates for Various Faults
Shown on Figure IX-3-2

Fault Identifier	Failure Mode	Failure Rate	Fault Duration (Hours)	Unavailability	Comments
MV1A,MV1B, MV1C,MVD, MVE,MV2A, MV2B,MV2C	Manual valve fails to remain open	$1.0\text{x}10^{-4}$/D	-	$1.0\text{x}10^{-4}$	
MOV720B	Motor operated valve does not open on demand	$1.0\text{x}10^{-3}$/D	-	$1.0\text{x}10^{-3}$	
MOV720AR, MOV720BR	Motor operated valve fails to remain open	$1.0\text{x}10^{-4}$/D	-	$1.0\text{x}10^{-4}$	
CVA,CVB,CVC	Check valve fails to remain open	$1.0\text{x}10^{-4}$/D	-	$1.0\text{x}10^{-4}$	
HXD,HXE	Heat exchanger large tube leak	$3.0\text{x}10^{-8}$/Hr	6570	$1.9\text{x}10^{-4}$	Failure rate, upper bound of small pipe rupture. Fault duration, every refueling.
PA,PB,PC	Pump does not start	$1.0\text{x}10^{-3}$/D	-	$1.0\text{x}10^{-3}$	
PR	Pipe rupture	$3.0\text{x}10^{-9}$/Hr	6570	$1.9\text{x}10^{-5}$	Failure rate, upper bound of large pipe rupture. Fault duration, every refueling.

Table IX-3-2 Failure Rates for Various Components In the Salt Water Cooling System

Component	Failure Mode	Failure Rate	Unavailability
Hydraulic Gate Valve	Fails to remain open	1.0×10^{-4}/D	1.0×10^{-4}
Motor operated Gate Valve	Fails to remain open	1.0×10^{-4}/D	1.0×10^{-4}
Butterfly Valves	Fails to remain open	1.0×10^{-4}/D	1.0×10^{-4}
SWCS Pump	Fails to start on demand	1.0×10^{-3}/D	1.0×10^{-3}
Heat Exchanger	Large Tube Leak	ε	ε

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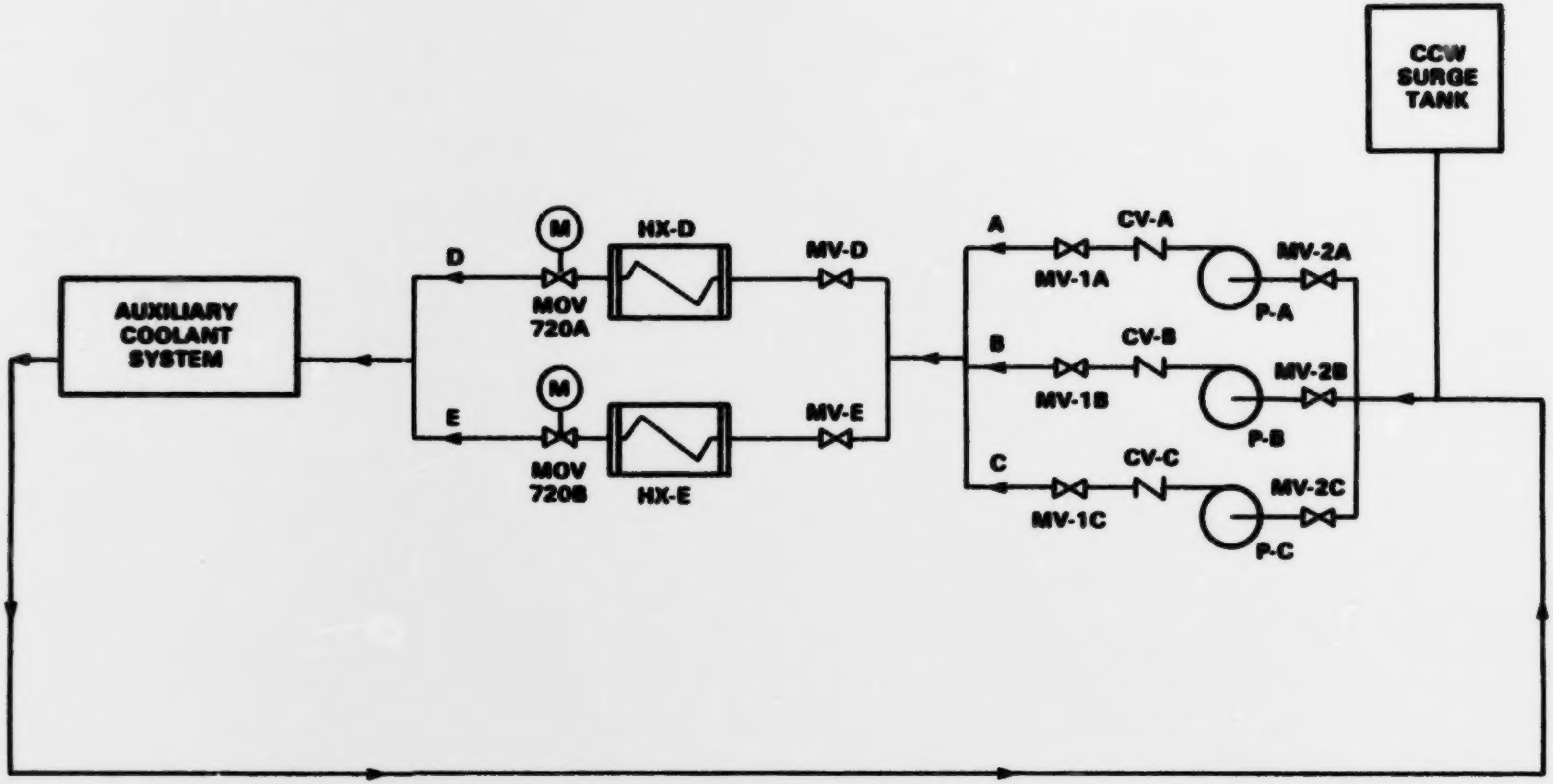
CCW
SURGE
TANK
AUXILIARY
COOLANT
SYSTEM
D
M
HX-D
MV-D
MOV
720A
E
M
MOV
720B
HX-E
MV-E
A
CV-A
MV-1A
P-A
MV-2A
B
CV-B
MV-1B
P-B
MV-2B
C
CV-C
MV-1C
P-C
MV-2C

Figure IX-3-1. SIMPLIFIED SCHEMATIC OF THE COMPONENT COOLING WATER SYSTEM

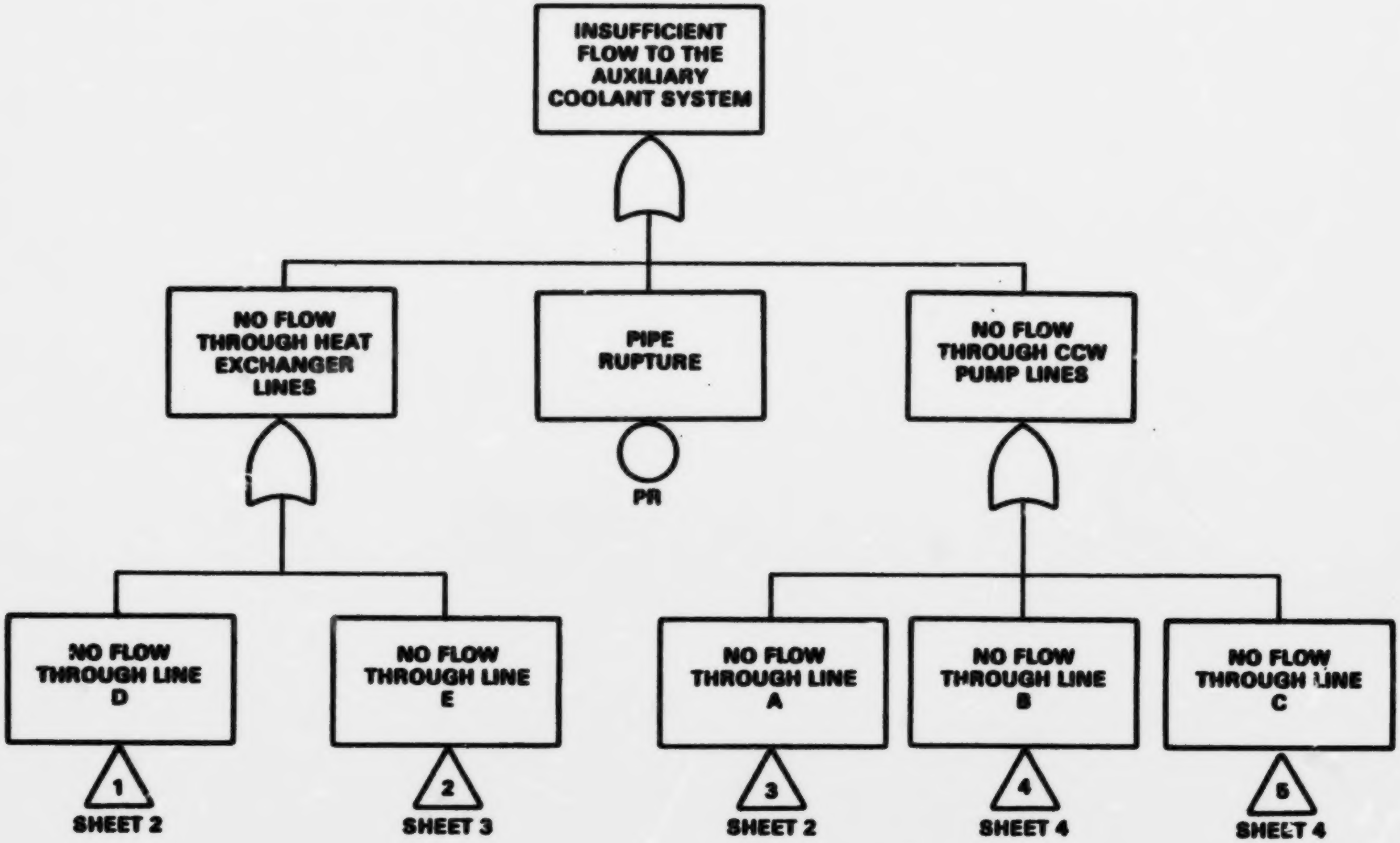
INSUFFICIENT FLOW TO THE AUXILIARY COOLANT SYSTEM
NO FLOW THROUGH HEAT EXCHANGER LINES
PIPE RUPTURE
PR
NO FLOW THROUGH CCW PUMP LINES
NO FLOW THROUGH LINE D
1
SHEET 2
NO FLOW THROUGH LINE E
2
SHEET 3
NO FLOW THROUGH LINE A
3
SHEET 2
NO FLOW THROUGH LINE B
4
SHEET 4
NO FLOW THROUGH LINE C
5
SHEET 4

Figure IX-3-2. FAULT TREE FOR THE EVENT "INSUFFICIENT FLOW TO THE AUXILIARY COOLANT SYSTEM"

SHEET 1

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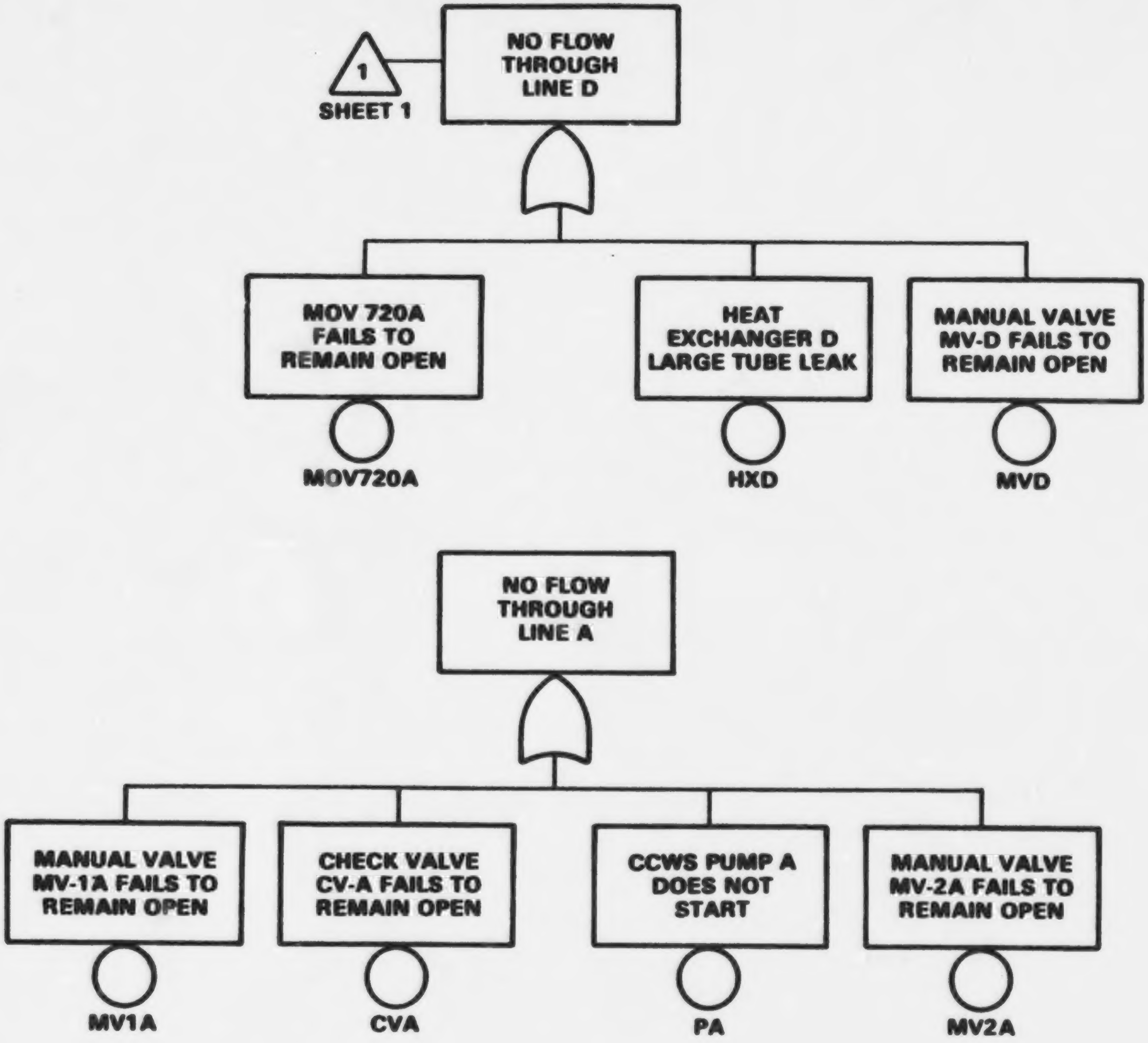
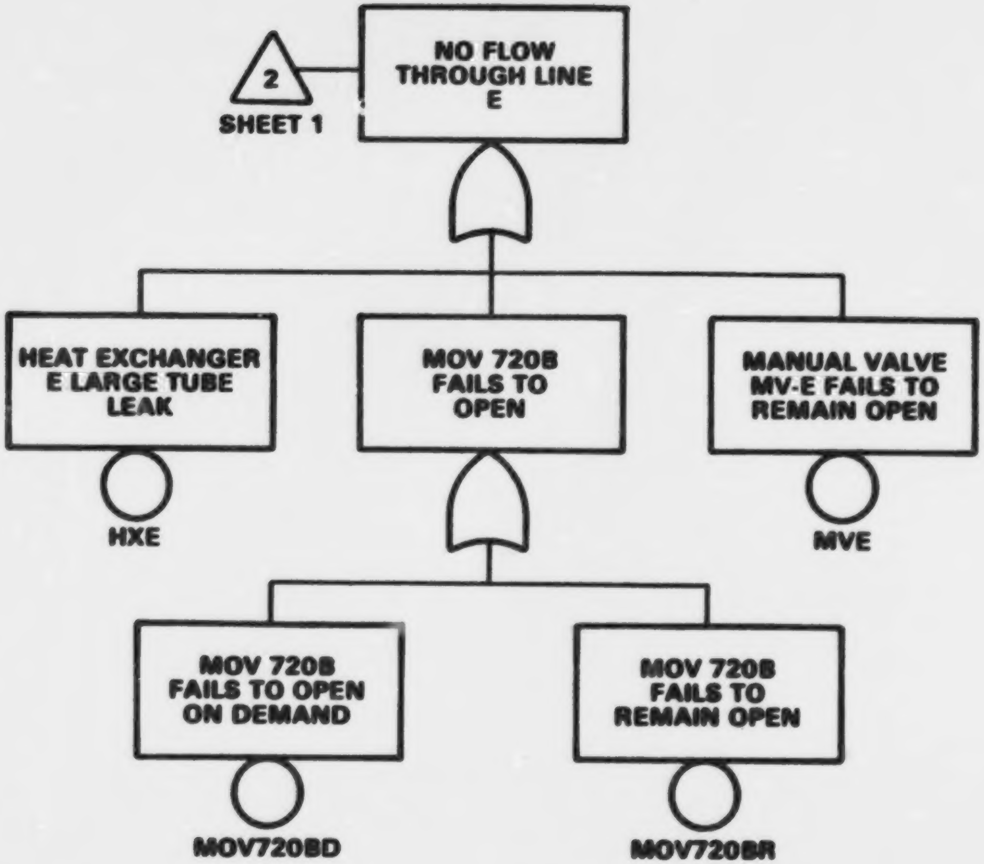

1
SHEET 1
NO FLOW THROUGH LINE D
MOV 720A FAILS TO REMAIN OPEN
HEAT EXCHANGER D LARGE TUBE LEAK
MANUAL VALVE MV-D FAILS TO REMAIN OPEN
MOV720A
HXD
MVD
NO FLOW THROUGH LINE A
MANUAL VALVE MV-1A FAILS TO REMAIN OPEN
CHECK VALVE CV-A FAILS TO REMAIN OPEN
CCWS PUMP A DOES NOT START
MANUAL VALVE MV-2A FAILS TO REMAIN OPEN
MV1A
CVA
PA
MV2A

Figure IX-3-2. (CONTINUED)

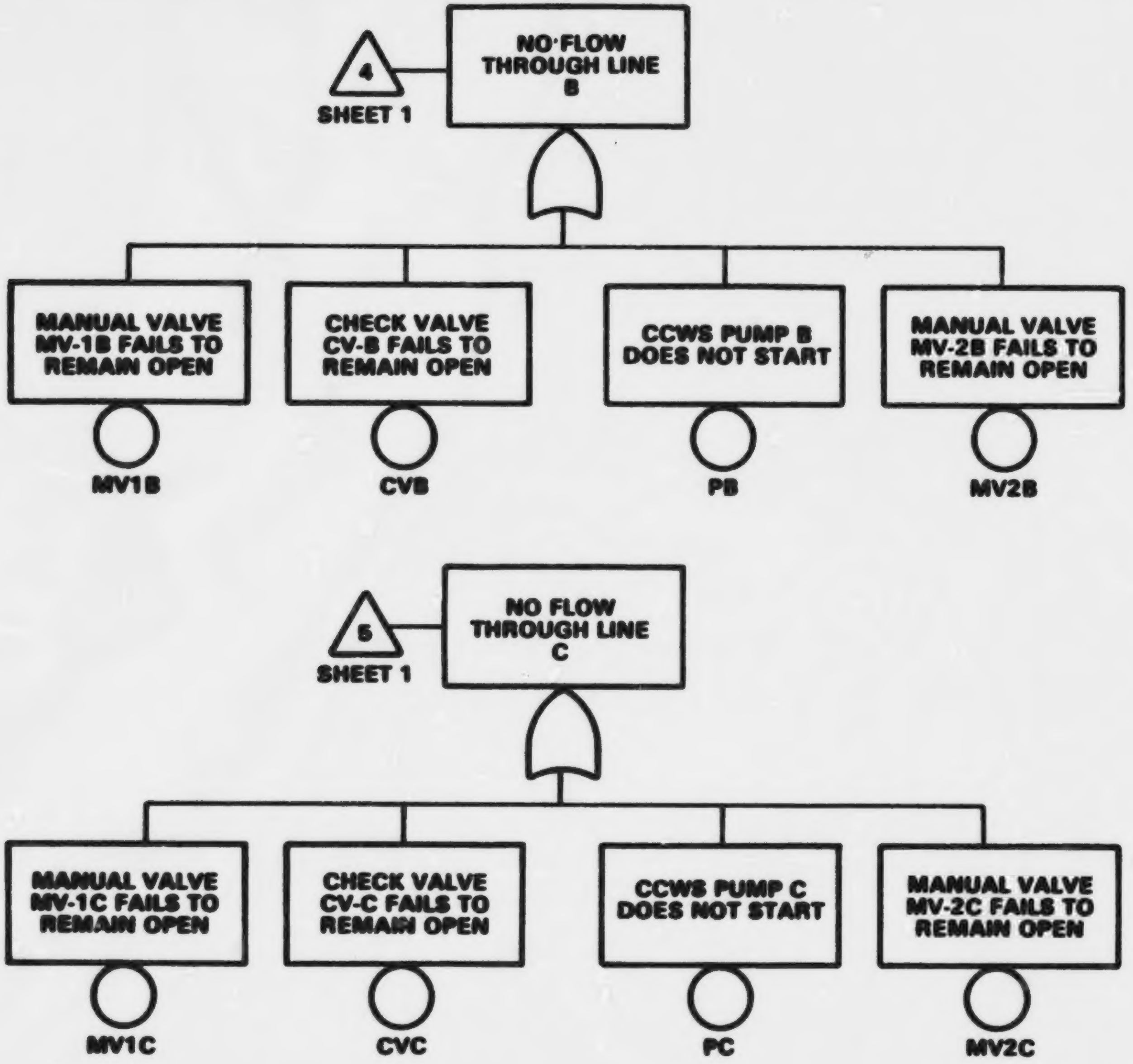
SHEET 2


2
SHEET 1
NO FLOW THROUGH LINE E
HEAT EXCHANGER E LARGE TUBE LEAK
MOV 720B FAILS TO OPEN
MANUAL VALVE MV-E FAILS TO REMAIN OPEN
HXE
MVE
MOV 720B FAILS TO OPEN ON DEMAND
MOV 720B FAILS TO REMAIN OPEN
MOV720BD
MOV720BR

SHEET 3

Figure IX-3-2. (CONTINUED)

360


4
SHEET 1
NO FLOW THROUGH LINE B
MANUAL VALVE MV-1B FAILS TO REMAIN OPEN
CHECK VALVE CV-B FAILS TO REMAIN OPEN
CCWS PUMP B DOES NOT START
MANUAL VALVE MV-2B FAILS TO REMAIN OPEN
MV1B
CVB
PB
MV2B
5
SHEET 1
NO FLOW THROUGH LINE C
MANUAL VALVE MV-1C FAILS TO REMAIN OPEN
CHECK VALVE CV-C FAILS TO REMAIN OPEN
CCWS PUMP C DOES NOT START
MANUAL VALVE MV-2C FAILS TO REMAIN OPEN
MV1C
CVC
PC
MV2C

SHEET 4

Figure IX-3-2. (CONTINUED)

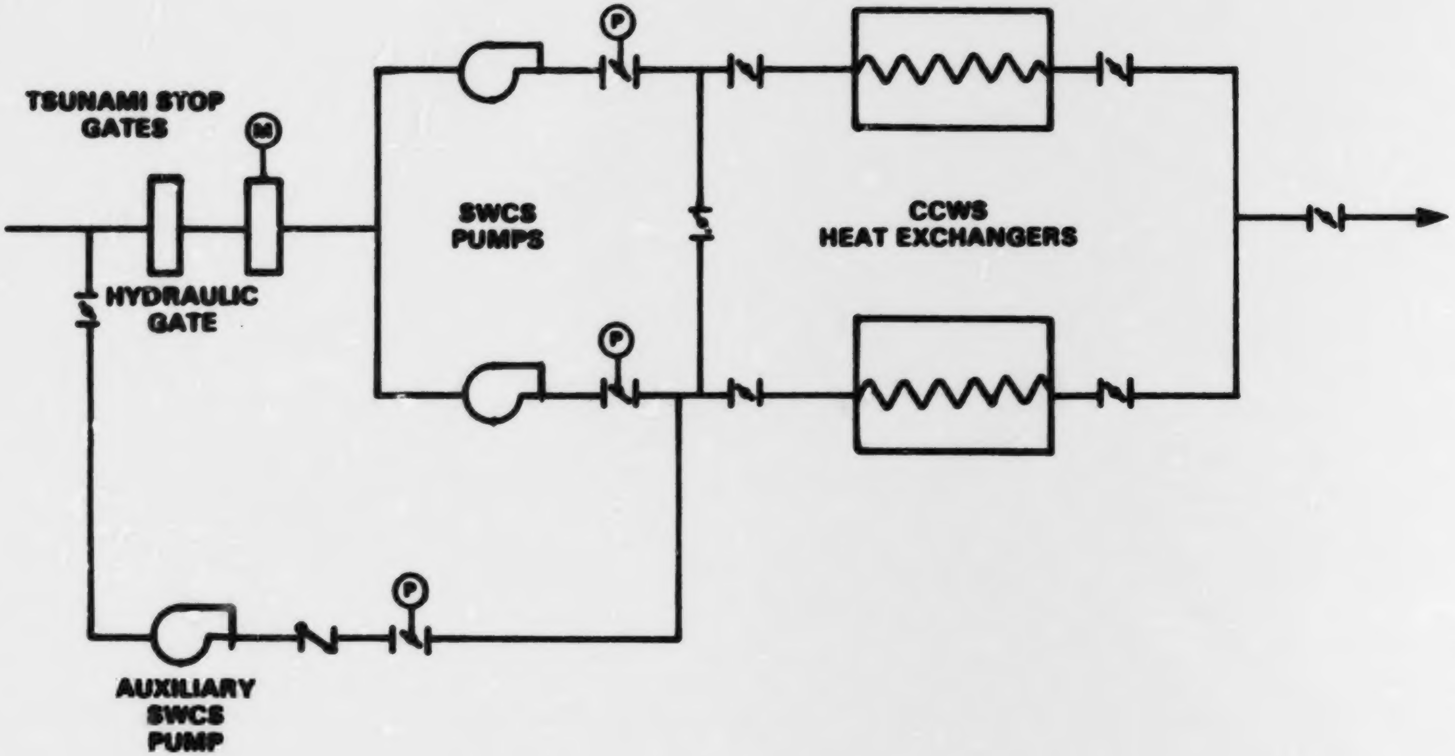

TSUNAMI STOP GATES
M
HYDRAULIC GATE
SWCS PUMPS
P
P
CCWS HEAT EXCHANGERS
P
AUXILIARY SWCS PUMP

Figure IX-3-3. SIMPLIFIED DIAGRAM OF THE SALT WATER COOLING SYSTEM

IX-5 Ventilation Systems

1. NRC Evaluation

The ventilation systems at a nuclear power plant must have the capability to provide a safe environment for plant personnel and for the engineered safety features. The systems reviewed under this topic are those defined as systems important to safety as outlined in Regulatory Guide 1.105. At San Onofre 1 the ventilation systems that service safety systems are the control room area ventilation system, the reactor auxiliary building ventilation system (RABVS), fuel storage building ventilation system and the engineered safety features ventilation system.

The main function of the RABVS is to provide ventilation for the areas within the building, which includes the charging pump room. The supply of fresh air to this building is provided by a single fan. Thus the ventilation system is subject to single failures that could disable the system.

In the engineered safety features ventilation system there are three areas where the ventilation system does not meet current criteria. These are the switchgear and cable spreading area, the 480V switchgear room, and the administrative building.

The switchgear and cable spreading ventilation system consists of a single fan that does not meet the single failure criteria. The equipment of interest in this area are the 4160V switchgear, 480V switchgear No. 1 and cables.

The essential equipment in the 480V switchgear room includes the 480V switchgear and cabling for the reactor protection and control system, instrumentation, emergency power and other safety related equipment. Ventilation for this area consists of a single fan which fails to meet the single failure criteria.

The administrative building ventilation system supplies heating and cooling to provide a comfortable working environment in the administrative building. The safety function performed by this system is the ventilation

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of the battery and inverter areas. Loss of ventilation to these rooms, especially the battery room where a loss of ventilation could lead to hydrogen buildup, could affect the operation of the batteries and inverters. The ventilation system does not meet the single failure criteria.

These are the only four areas where the San Onofre 1 ventilation systems do not meet current criteria.

2. NRC Recommendation

For the ventilation systems not in compliance with current criteria the NRC has recommended that the licensee should provide analyses showing that ventilation to those areas is not required for an acceptable operating environment. If unable to do so, the licensee should propose corrective measures for each ventilation system.

3. System Affected

The systems affected include the chemical and volume control system (CVCS), the AC power system and the DC power system.

4. Comments

The effects of a loss of ventilation to areas housing safety-related equipment are being evaluated by the staff of San Onofre 1, but the results are not available for this study. Therefore this analysis will be based on the information provided and conservative assumptions to assess the potential risk due to failure of the ventilation systems.

The assumption is made that all safety-related equipment requires adequate ventilation to function properly. Therefore, a loss of ventilation will impair the operation of this equipment. A second assumption is based on results from previous PRAs. It is assumed that cable operability (i.e., the ability to conduct electricity) is not affected by a loss of ventilation. This assumption is based on previous PRA findings that cables do not generate a significant amount of heat while in operation, and are able to retain their integrity even when exposed to an elevated temperature environment. Even in the case where cables are placed in the same area as heat-generating equipment, under extreme (high temperature) condition, the equipment is deemed to fail (and therefore stop generating additional heat) before the cables would. Thus, this analysis will assume that ventilation is not required for cables to maintain their integrity.

With these assumptions the analysis for the risk potential associated with the failure of the ventilation systems is presented in the following section. Unless otherwise stated all data is WASH-1400 data.

5. Analysis

The loss of ventilation in the switchgear and cable spreading room can affect San Onofre 1 in two ways. Loss of ventilation could lead to a failure of the AC power system during normal operation leading to a plant trip, i.e., loss of ventilation could be an accident initiator. Alternately, following an accident initiator, LOCA or transient, the loss of ventilation in this room could cause a loss of AC power hindering efforts to mitigate the results of the original initiating event.

The frequency of a loss of ventilation in the switchgear and cable spreading room is the frequency of failure of the single fan that provides ventilation in the room. This can be determined from the equation

$$\lambda T$$

where λ = fan failure rate = 2.8E-6/hr
T = hours in a year = 8760 hrs/yr.

The fan failure rate is based on IEEE-500 data. The frequency of fan failure is 2.5E-2/yr.

Under the assumptions of this analysis, that a loss of ventilation fails all equipment in a room except cabling, this would be the frequency of a loss of all AC power, i.e., station blackout. All AC power is lost since the 4160V switchgear is in this room and both onsite and offsite power require that this switchgear be operational. This is a very large frequency

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for a station blackout. For comparison purposes consider that the frequency of a loss of offsite power (.1/yr) plus the mechanical failure of the two diesel generators to start (3E-2/demand for each diesel) yields a station blackout frequency of approximately 1E-4/yr. This is normally a dominant station blackout sequence.

To lose all cooling to the core the only failure required other than a total loss of AC power would be the failure of the turbine driven auxiliary feedwater pump train. The failure of this portion of the auxiliary feedwater system can be approximated by modeling the failure of the pump itself. Assuming a mission time of 24 hours, consistent with the assumptions made in the IREP studies, the failure probability of the turbine driven auxiliary feedwater pump would be:

$$\lambda_d + \lambda_o t$$

where

λ_d = turbine driven pump failure to start probability = 3E-3

λ_o = operating failure rate = 3E-5

t = 24 hours.

This yields a pump failure probability of 3.7E-3. Combined with the frequency of a loss of ventilation this yields a frequency for a loss of cooling to the core of

$$(3.7E-3)(2E-2/yr)$$
$$= 7.4E-5/yr.$$

In response to an accident initiator the failure of the fan would still lead to a loss of power. However, in this case the time interval of concern is only the time following the initiator. Since the ventilation system is required it must have been operating prior to the initiating event. Using the mission time following an initiating event from the IREP studies, 24 hours, the probability of fan failure following an initiating event would be

$$(2.8E-6/hr)(24 hr)$$
$$= 6.7E-5.$$

Loss of AC power would fail all normal means of cooling the core except for the turbine driven auxiliary feedwater pump. As calculated above, the failure probability of the turbine driven auxiliary feedwater pump train can be approximated as 3.7E-3.

For the initiating event frequency we will use a transient frequency of 8/yr which is consistent with the ANO-1 IREP study. From this the frequency of a loss of cooling to the reactor core caused in part by loss of ventilation in the switchgear and cable spreading room would be

F(loss of cooling) = F(transient)P(vent failure)P(aux. feed. failure)
= 8/yr (6.7E-5)(3.7E-3)
= 2E-6/yr

Loss of cooling to the core will eventually lead to a core melt. The plants used as a reference for this analysis typically have core melt frequencies on the order of 3E-5 to 1E-4. Loss of ventilation in the switchgear and cable spreading room can conceivably result in core melt frequencies of this magnitude. Thus it would be a dominant contributor, under the constraints imposed by the assumptions of this analysis, to plant risk.

The analysis for a ventilation failure in the 480V switchgear room is similar to that for the switchgear and cable spreading room. The major difference is that a loss of ventilation in this room affects only one of the two AC power trains. One result of this difference is that following a transient both auxiliary feedwater pumps would normally be available. (The electric driven pump can be powered through either AC power train.) The loss of the switchgears in this room would affect the recirculation system (one of the two pumps), the residual heat removal system (one of the two pumps), the salt water system and the component cooling water system. Failure of the switchgear in this room would degrade the operation of these systems, e.g., remove redundancies, but would not fail any of the systems.

Through the use of the auxiliary feedwater system it is possible to maintain San Onofre 1 in a hot shutdown condition. This system is virtually unaffected by the loss of ventilation in this switchgear room. From PRAs done on plants with similar auxiliary feedwater systems the failure probability of the auxiliary feedwater system is on the order of 3E-4. The combination of a 480V switchgear room ventilation system failure, as an accident initiator (Frequency = 2.5E-2/yr), and auxiliary feedwater system failure has a frequency of 8E-6/yr. To achieve a core melt the unaffected portions of the core cooling systems, the residual heat removal and recirculation systems, would also have to fail. These failures would reduce the frequency of core melt due to a ventilation failure by a couple orders of magnitude below 8E-6/yr, to a point where this type of event would not significantly affect the core melt risk at San Onofre 1.

If the ventilation system fails following a transient initiator the frequency of the combination of transient, ventilation failure and auxiliary feedwater failure is approximately

$$\begin{aligned} & F(\text{transient})P(\text{vent failure})P(\text{aux. feedwater failure}) \\ &= (8/\text{yr})(6.7\text{E-}5)(3\text{E-}4) \\ &= 1.6\text{E-}8/\text{yr} \end{aligned}$$

This combination would not significantly affect the core melt frequency of San Onofre 1.

Loss of the reactor auxiliary building ventilation system affects the charging pumps. No other components important to safety are affected. There are two components in this ventilation system whose failure will result in the loss of the ventilation system. These are the air supply unit (A-25) and a differential pressure switch used to shut off the air supply unit.

The air supply unit will be modeled as a single fan with a failure rate of 2.8E-6/hr. As in the previous analyses the probability of the air handling unit failing following an accident initiator is 6.7E-5. From IEEE-500 the failure rate for the differential pressure switch is 2.85E-6/hr. In the 24 hours following an accident initiator the pressure switch probability of failure would be

$$\begin{aligned} & (2.85\text{E-}6/\text{hr})(24\text{ hrs}) \\ &= 6.8\text{E-}5 \end{aligned}$$

The probability of loss of ventilation to the charging pumps would be the sum of the two failure probabilities, 1.4E-4.

In response to a LOCA the charging system can be used in conjunction with the safety injection system to provide inventory to the reactor coolant system. LOCA frequencies for PWRs range from 1E-4 to 2E-2/yr depending on the LOCA size and the plant of interest. Using the larger LOCA frequencies the frequency of a charging system failure due to a ventilation system failure following a LOCA would be

$$\begin{aligned}&(1.4E-4)(2E-2/yr)\\&= 3E-6/yr.\end{aligned}$$

For core damage to occur the safety injection system must also fail. The failure of this additional system would reduce the frequency of the combination of events to a value below 1E-6/yr. (At San Onofre 1 the safety injection system consists of the two feedwater pumps and two safety injection pumps. One feedwater and one safety injection pump comprise one train of the safety injection system. Although the San Onofre 1 safety injection system is not typical because of the use of the feedwater pumps the redundant trains and initiation logic is similar to other PWR safety injection systems. These safety injection systems typically have failure probabilities on the order of 10^{-2}. Therefore it is not unreasonable to assume that the additional safety injection failure required to lose the coolant makeup capability, given a LOCA, with a ventilation failure induced failure of the charging pumps would have a frequency of less than 1E-6/yr.)

If ventilation is required for the station battery room and the inverter room, both in the administrative building, then a failure of the administrative building ventilation system could affect the core melt frequency at San Onofre 1. Only one set of batteries is located in this battery room; therefore, loss of ventilation to this area does not affect the entire DC power system.

Ventilation to these areas is supplied by a single fan. From the calculation performed for the switch gear and cable spreading room the frequency of ventilation system failure will be 2.5E-2/yr. With the assumption that ventilation is required for the inverters this is the frequency of a transient. (The loss of all three inverters will result in control rod insertion.) This is not a significant fraction of the expected transient frequency for a PWR: on the order of 6-10/year. However, this initiator could also cause a loss of one of the DC power trains. The loss of ventilation could result in the failure of the battery chargers and batteries of DC power train 1.

The analysis for SEP topic VIII-3.B provides an unavailability for a DC power train given a loss of offsite power of 4.1E-4. Even if we assume one loss of offsite power per year the ventilation induced loss of DC power train 1 is significantly larger than the system failure frequency due to other causes. Although the ventilation system failure affects only one DC power train it is a significant contributor to the DC power train failure frequency. The proven importance of the DC power system for PWRs makes the contribution of ventilation system failures a high risk significance topic.

(The failure of the ventilation system after a transient initiator is also risk significant. The probability of a fan failure, as calculated in the switchgear and cable spreading area ventilation analysis, following a transient is 6.7E-5. This is slightly more than 10% of the failure probability of the DC power train following a loss of offsite power. Although the ventilation failure would not be the dominant contributor to the DC power train 1 failure probability, it would be a significant contributor.)

6. Conclusion

In analyzing the potential risk due to a loss of ventilation in these four areas of the plant it has been assumed that ventilation is required for all the equipment in each area. This assumption results in a conservative estimation of the effects of a loss of ventilation. Therefore, the results of these analyses should be considered as an absolute upper bound on the potential significance of the ventilation system failures. These results should be used to determine whether further analysis of ventilation system requirements is needed. A ranking of low risk significance implies no further analysis is needed. A ranking of high or medium implies that further analysis as to the need for ventilation is recommended.

Ventilation failures in two of the areas analyzed here do not significantly affect the risk due to failure of the systems in those areas. The loss of ventilation in both the reactor auxiliary building and the 480V switchgear room does affect the system, or subsystem, reliability but not the core melt risk, to any significant extent. This is due primarily to the fact that the equipment in these two areas supply redundant capabilities. The charging pumps in the reactor auxiliary building provide the same function, following a LOCA, as the safety injection system. Loss of ventilation in the 480V switchgear room affects only parts of one of the AC power trains. For these two areas the loss of ventilation is rated as of low risk significance.

A loss of ventilation in the switchgear and cable spreading room could result in the loss of all AC power. With the single fan, the frequency of a ventilation system failure causing a loss of all AC power is relatively high. Station blackout generally is a significant contributor to plant risk. We therefore rate this issue to be of high risk significance.

If ventilation is required for the station batteries, both for heat removal and to prevent hydrogen buildup, the failure of a single fan could lead to the loss of one train of the DC station power system. The loss of the station batteries has generally contributed to the dominant accident sequences in PWR PRAs. The frequency of battery failure due to ventilation system failure is relatively high, when compared to other possible methods of losing the batteries. For these reasons, we rate this issue to be of high risk significance.

For this issue it must be remembered that it has been assumed that ventilation is required for all the equipment in the areas analyzed. The results of this analysis should be used only to determine if further analyses of the ventilation requirements are needed.

XV-2 Spectrum of Steam System Piping

1. NRC Evaluation

NRC staff evaluation of this topic considered the system's ability to mitigate or prevent the consequences of steam line breaks. Due to design features of the secondary side of the steam generator systems at San Onofre Unit 1 the staff's evaluation also considered steam generator thermal shock. The NRC staff concluded that for steam line breaks the following:

- the pressure in the reactor coolant and main steam systems is maintained well below the design pressure in all cases analyzed

- that for the worst case that after 200 seconds the reactor coolant system stabilized at 1200 PSI and 250°F

- the Licensee's proposed addition of a motor driven auxiliary feedwater pump will eliminate the vulnerability to loss of function due to the postulated single failure of the existing motor driven pump.

With regard to steam generator thermal shock the staff concludes the steam generators should not lose their component integrity or their ability to cool the primary system.

2. NRC Recommendations

The Licensee should address the qualification of the main feedwater system to function in the required mode under accident conditions.

3. Systems Affected

Steamline breaks have the potential for offsite consequences. Several subsystems are also affected, e.g., main and auxiliary feedwater system, steam generators, emergency response procedures, etc.

4. Comments

The NRC review of the analysis of a spectrum of postulated steamline breaks at San Onofre Unit 1 concludes that with respect to steamline breaks it is acceptable. The staff further concludes that installation of a third auxiliary feedwater pump (motor driven) will provide assurance that in the event of a steamline break the reactor secondary cooling system will not be vulnerable to a single failure scenario.

5. Analysis

None

6. Conclusion

Given the changes in the emergency procedures and the hardware changes that have been completed the public risk due to steamline breaks at San Onofre Unit 1 are low.

XV-7 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

1. NRC Evaluation

On loss of forced reactor coolant flow NRC staff concludes that loss of flow does not affect minimum DNBR. However, NRC could not conclude whether peak reactor coolant pressure would exceed the allowable limits. For reactor coolant pump rotor seizure or shaft break, NRC could not conclude whether the consequences of these events satisfy the review criteria.

2. NRC Recommendation

The Licensee should demonstrate that the consequences of the loss of flow satisfy the review criteria or are acceptable on another basis.

3. Systems Affected

Primary reactor coolant systems failure causes fuel damage and leads to offsite consequences.

4. Comments

None

5. Analysis

PRAs have shown that the dominant contributor to risk from a nuclear power plant is a core melt accident. Although it is conceivable that a loss of flow in the primary due to a pump seizure or shaft break could lead to fuel damage and offsite consequences, the probability of such an event is small. On loss of coolant flow or low flow conditions the reactor safety system automatically scrams the reactor. To have any offsite consequences requires failure of the safety systems (RHR, etc.) or breach of the containment system. The probability of reactor coolant pump failure, including leakage/rupture, "loss of function" and "does not continue to run" is $3x10^{-6}$/hr (NUREG/CR-1205, P 35). The data on which this estimate is based shows that only 2 of 124 events involved a running pump (i.e., a reactor coolant pump) "loss of function" or "does not continue to run" failure. The seizure of a rotor or shaft break would be a "loss of function" or "does not continue to run" failure. Thus the probability of rotor seizure or shaft break is less than 5×10^{-8}/hr. On an annual basis the probability is on the order of 4×10^{-4} or less. The overall probability of a shaft break or rotor seizure causing offsite consequence would be the product of the probability of the failure times the probability that the reactor protective system fails, a small probability.

6. Conclusions

This issue has low potential for significantly reducing the risk from the operation of the San Onofre Unit 1. Additionally, this issue was completely resolved before completion of the final report.

REFERENCES

1. Baranowsky, P.W., A.M. Kolaczkowski and M.A. Fedele, "A Probabilistic Safety Analysis of DC Power Supply Requirements for Nuclear Power Plants," NUREG-0666, April 1981.

2. IEEE Guide to the Collection and Presentation of Electrical, Electronics, and Sensing Component Reliability Data for Nuclear Generating Stations, IEEE Std 500-1977 (1977).

3. Kolb, G.J., et. al., "Interim Reliability Evaluation Program: Analysis of the Arkansas Nuclear One - Unit 1 Nuclear Power Plant," NUREG/CR-2787, June 1982.

4. Memorandum for D.G. Eisenhut, NRC, from T.E. Munly, NRC, on the subject of Reactor Coolant Pump Seal Failure.

5. Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants, WASH-1400 (NUREG-75/014), U.S. Nuclear Regulatory Commission, October 1975.

6 Swain, A.D., and H.E. Gultmann, "Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Applications," NUREG/CR-1278, October 1980.

7. Nonelectronic Parts Reliability Data, Reliability Analysis Center, Rome Air Development Center, NPRD-2.

APPENDIX E

REFERENCES TO CORRESPONDENCE FOR EACH TOPIC EVALUATED

SEP Topic No.	Date	Reference
II-1.A	11/7/79	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: San Onofre Unit 1 - SEP Topic II-1.A.
II-1.B	11/7/79	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: San Onofre Unit 1 - SEP Topic II-1.B.
II-1.C	5/3/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic II-1.C, Potential Hazards Due to Nearby Industrial, Transportation and Military Facilities (San Onofre Unit 1).
II-2.A	4/27/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic II-2.A, Severe Weather Phenomena.
II-2.C	11/18/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic II-2.C, Atmospheric Transport and Diffusion Characteristics for Accident Analysis (San Onofre Unit 1).
II-3.A	1/31/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topics II-3.A, Hydrologic Description; II-3.B, Flooding Potential and Protection Requirements; II-3.B.1, Capability of Operating Plants To Cope With Design Basis Flooding Conditions; and II-3.C, Safety-Related Water Supply (Ultimate Heat Sink).
	8/27/84	Letter from W. Paulson (NRC) to K. Baskin (SCE), Subject: San Onofre Unit 1 - Hydrology Issues.
II-3.B		See references for Topic II-3.A.
II-3.B.1		See references for Topic II-3.A.
II-3.C		See references for Topic II-3.A.
II-4	11/18/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Nuclear Generating Station, Unit 1 - SEP Topics II-4, Geology and Seismology, and II-4.B, Proximity of Capable Tectonic Structures in Plant Vicinity.
II-4.A	9/16/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: Free Field Ground Motion To Be Used in the Seismic Reevaluation of San Onofre Nuclear Generating Station, Unit 1.
	8/16/84	Letter from D. M. Crutchfield (NRC) to K. Baskin (SCE), Subject: Seismic Ground Motion - San Onofre Nuclear Generating Station, Unit 1.

SEP Topic No.	Date	Reference
II-4.B	11/18/82	See reference for Topic II-4.
II-4.C		See references for Topic II-4.A.
II-4.D	11/12/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic II-4.D, Stability of Slopes - San Onofre Unit 1.
II-4.F	12/1/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic II-4.F, Settlement of Foundations and Buried Equipment - San Onofre 1.
II-4.F	11/13/84	Letter from W. Paulson (NRC) to K. Baskin (SCE), Subject: SEP Topics II-4.F, Settlement of Foundations - Evaluation of Sea Wall, San Onofre Unit 1.
III-1	11/18/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topics III-1 and VII-3 - San Onofre Unit 1.
	6/25/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic III-1, San Onofre Nuclear Generating Station, Unit 1.
	1/26/83	Letter from R. W. Krieger (SCE) to D. M. Crutchfield (NRC), Subject: SEP Topics III-1 and III-7.B (San Onofre Nuclear Generating Station, Unit 1).
	4/23/84	Letter from D. M. Crutchfield (NRC) to K. Baskin (SCE), Subject: SEP Topic III-1, Quality Group Classification of Components and Systems - San Onofre Nuclear Generating Station, Unit 1.
III-2	2/1/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic III-2, Wind and Tornado Loadings - San Onofre Unit 1.
	4/26/84	Letter from D. M. Crutchfield (NRC) to K. Baskin (SCE), Subject: SEP Topics III-2, Wind and Tornado Loadings and III-7.B, Design Codes, Design Criteria and Load Combinations - San Onofre Unit 1.
III-3.A	12/13/84	Letter from J. Zwolinski (NRC) to K. Baskin (SCE), Subject: SEP Topic III-3.A, Effect of High Water Level on Structures - San Onofre Nuclear Generating Station, Unit 1.
III-3.C	11/27/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic III-3.C, Inservice Inspection of Water Control Structures.

SEP Topic No.	Date	Reference
III-4.A	11/19/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic III-4.A, Tornado Missiles, San Onofre Unit 1.
III-4.B	2/1/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic III-4.B, Turbine Missiles, San Onofre Unit 1.
III-4.C	10/12/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: Systematic Evaluation Program III-4.C, Internally Generated Missiles - San Onofre Unit 1.
III-4.D	11/16/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic III-4.D, Site Proximity Missiles - San Onofre Unit 1.
III-5.A	4/26/84	Letter from D. M. Crutchfield (NRC) to K. Baskin (SCE), Subject: SEP Topic III-5.A, Effects of Pipe Break on Structures, Systems and Components Inside Containment San Onofre Nuclear Generating Station, Unit No. 1.
III-5.B	4/23/84	Letter from D. M. Crutchfield (NRC) to K. Baskin (SCE), Subject: San Onofre Unit 1 - SEP Topic III-5.B, Pipe Break Outside Containment
III-6	11/21/84	Letter from D. G. Eisenhut (NRC) to K. Baskin (SCE), Subject: Contingent Rescission of Suspension.
III-7.B	9/21/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: Systematic Evaluation Program III-7.B, Design Codes, Design Criteria and Load Combinations San Onofre Unit 1.
	1/26/83	See reference for Topic III-1.
	4/26/84	See reference for Topic III-2.
III-7.D	4/23/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic III-7.D, Containment Structural Integrity Test.
III-8.A	12/28/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: Systematic Evaluation Program Topic III-8.A, Loose Parts Monitoring and Core Barrel Vibration Program - San Onofre Unit 1.
III-8.C	1/29/80	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: San Onofre Unit 1 - Irradiation Damage, Use of Sensitized Stainless Steel and Fatigue Resistance (SEP Topic III-8.C).

SEP Topic No.	Date	Reference
III-10.A	7/24/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic III-10.A, Thermal-Overload Protection - San Onofre Unit 1.
III-10.B	11/8/79	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: Completion of Topic III-10.B, Pump Flywheel Integrity - San Onofre Unit 1.
IV-1.A	11/13/79	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: San Onofre Unit 1 - SEP Topic IV-1.A.
IV-2	1/3/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic IV-2.
V-5	3/7/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic V-5, RCPB Leakage Detection, San Onofre Nuclear Generating Station, Unit 1.
V-6	3/5/80	Letter from D. L. Ziemann (NRC) to R. Dietch (SCE), Subject: Completion of SEP Topic V-6, Reactor Vessel Integrity - San Onofre Unit 1.
	1/10/84	Letter from W. Paulson (NRC) to K. Baskin (SCE), Subject: San Onofre Nuclear Generating Station, Unit 1 - SEP Topic V-6, Reactor Vessel Integrity.
V-7	1/7/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: Systematic Evaluation Program Topic V-7, Reactor Coolant Pump Overspeed - San Onofre Unit 1.
V-10.A	1/7/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic V-10.A, Residual Heat Removal System Heat Exchanger Tube Failure - San Onofre Unit 1.
V-10.B	11/12/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topics V-10.B, RHR System Reliability; V-11.B, RHR Interlock Requirements; and VII-3, Systems Required for Safe Shutdown (Safe Shutdown Systems Report).
V-11.A	8/3/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic V-11.A, Requirements for Isolation of High and Low Pressure Systems Safety Evaluation for San Onofre Unit 1.

SEP Topic No.	Date	References
V-11.B	2/4/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic V-11.B, RHR Interlock Requirements - San Onofre Unit 1.
	11/12/82	See reference for Topic V-10.B
VI-1	7/13/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic VI-1, Organic Materials and Post-Accident Chemistry (San Onofre Unit 1).
VI-2.D	1/12/82	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: Systematic Evaluation Program (SEP) for San Onofre Nuclear Generating Station, Unit 1 - Evaluation Report on Topics VI-2.D and VI-3.
VI-2.D	5/27/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: Systematic Evaluation Program (SEP) for San Onofre Nuclear Generating Station, Unit 1 - Evaluation Report on Topics VI-2.D and VI-3.
	2/24/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topics VI-2.D, VI-3 and VII-3.B, San Onofre Nuclear Generating Station, Unit 1.
VI-3		See references for Topic VI-2.D.
VI-4	3/3/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: Forwarding Draft Evaluation Report of SEP Topic VI-5, Containment Isolation System for the San Onofre Nuclear Generating Station, Unit 1.
	9/16/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic VI-4, Containment Isolation Systems.
	12/6/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic VI-4, Containment Isolation System (Electrical).
VI-4	10/27/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Nuclear Generating Station, Unit 1 - SEP Topic VI-4, Containment Isolation System (Electrical).
VI-6	8/12/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic VI-7.A.1.
VI-7.A.3	11/18/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VI-7.A.3, ECCS Actuation System Safety Evaluation Report - San Onofre Unit 1.

SEP Topic No.	Date	References
VI-7.A.3	2/1/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic VI-7.A.3, ECCS Actuation System Final Safety Evaluation Report - San Onofre Nuclear Generating Station, Unit 1.
VI-7.B	9/4/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VI-7.B, San Onofre Unit 1.
	11/24/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1, SEP Topic VI-7.B, ESF Switchover From Injection to Recirculation Mode (Automatic ECCS Realignment).
VI-7.C	1/6/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topics VI-7.C, ECCS Single Failure Criterion and Requirements for Locking Out Power to Valves, and VI-7.C.2, Failure Mode Analysis (San Onofre Unit 1).
VI-7.C.1	8/3/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VI-7.C.1, Appendix K - Electrical Instrumentation and Control (EI&C) Re-reviews, Safety Evaluation for San Onofre Unit 1.
VI-7.C.2	1/6/83	See reference for Topic VI-7.C.
VI-7.D	8/18/78	Letter from D. G. Eisenhut (NRC) to J. H. Drake (SCE), Subject: Evaluation of Eight SEP Topics.
VI-10.A	8/28/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VI-10.A, Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing, Safety Evaluation for San Onofre Unit 1.
	4/28/83	Letter from W. A. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic VI-10.A, Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing, Final Safety Evaluation Report for the San Onofre Nuclear Generating Station, Unit 1.
VI-10.B	11/15/79	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: SEP Topic VI-10.B - San Onofre Unit 1.
VII-1.A	9/9/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VII-1.A, Isolation of Reactor Protection System from Non-Safety Systems, Including Qualification of Isolation Devices - San Onofre Unit 1.

SEP Topic No.	Date	Reference
VII-1.A	2/10/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic VII-1.A, San Onofre Unit 1.
VII-1.B	8/17/78	See reference for Topic VI-7.D.
VII-2	11/17/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VII-2, Engineered Safety Features (ESF) System Control Logic and Design - San Onofre Unit 1.
VII-2	3/30/83	Letter from W. A. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic VII-2, Engineering Safety Features (ESF) System Control Logic and Design - San Onofre Unit 1.
VII-3	11/18/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VII-3, Systems Required for Safe Shutdown, Draft Safety Evaluation for San Onofre.
	6/4/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - Evaluation of SEP Topic VII-3, Systems Required for Safe Shutdown (EICS Matters).
	11/12/82	See reference for Topic V-10.B.
VII-6	8/28/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: Topic VII-6, Frequency Decay (San Onofre Unit 1).
VIII-1.A	11/23/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic VIII-1.A, Potential Equipment Failures Associated With Degraded Grid Voltage - San Onofre Unit 1.
VIII-2	3/2/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VIII-2, Onsite Emergency Power Systems - Diesel Generator Safety Evaluation for San Onofre Unit 1.
	7/31/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VIII-2, Onsite Emergency Power Systems - Diesel Generator, Safety Evaluation for San Onofre Unit 1.
VIII-3.A	11/7/79	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: SEP Topic VIII-3.A, Safety Evaluation for San Onofre Unit 1.

SEP Topic No.	Date	Reference
VIII-3.B	1/28/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VIII-3.B, DC Power System Bus Voltage Monitoring and Annunciation, Revised Safety Evaluation for San Onofre Unit 1.
	7/24/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VIII-3.B.
	2/24/83	See reference for Topic VI-2.D.
VIII-4	12/31/81	Letter from D, M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic VIII-4, Electrical Penetrations of Reactor Containment - San Onofre Unit 1.
	12/6/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic VIII-4, Electrical Penetrations of Reactor Containment Safety Evaluation Report for San Onofre Nuclear Generating Station, Unit 1.
IX-1	12/7/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: Topic IX-1, Fuel Storage, SONGS 1.
IX-3	12/27/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic IX-3, Station Service and Cooling Water System - San Onofre Nuclear Generating Station, Unit 1.
IX-4	7/16/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic IX-4.
IX-5	11/2/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: Forwarding Evaluation Report of SEP Topic IX-5, Ventilation Systems for the San Onofre Nuclear Generating Station, Unit 1.
IX-6	12/2/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic IX-6, Fire Protection - San Onofre Nuclear Generating Station, Unit 1.
XIII-2	1/22/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: Amendment No. 51.
XV-1	7/22/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre 1 - SEP Topic XV-1.
XV-2	1/29/80	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: Completion of SEP Topic XV-18 (XV-2) - San Onofre 1.

SEP Topic No.	Date	Reference
XV-2	12/17/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-2.
XV-3	8/26/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: SEP Topic XV-3, XV-19 (Systems) - San Onofre Unit 1.
XV-4	4/5/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topics XV-4, XV-12 (Systems) and XV-16 - San Onofre Unit 1.
XV-5	3/14/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-5.
XV-6	3/3/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-6.
XV-7	10/5/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: SEP Topic XV-7, San Onofre Unit 1.
XV-8	11/19/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topics XV-8 and XV-12 (Systems).
XV-9	2/24/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-9.
XV-10	3/29/83	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-10, Chemical and Volume Control System Malfunction That Results in a Decrease in Boron Concentration in the Reactor Coolant.
	4/27/84	Letter from D. M. Crutchfield (NRC) to K. Baskin (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-10.
XV-12	1/29/80	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: SEP Topic XV-12, Radiological Consequences - San Onofre Unit 1.
	4/5/82	See reference for Topic XV-4.
XV-14	2/22/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-14.
XV-15	4/20/82	Letter from W. Paulson (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-15.
XV-16	4/5/82	See reference for Topic XV-4.

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SEP Topic No.	Date	Reference
XV-17	1/29/80	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-17, Radiological Consequences.
	12/7/81	Letter from D. M. Crutchfield (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-17 (Systems).
XV-19	1/29/80	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-19, Radiological Consequences.
	8/26/81	See reference for Topic XV-3.
XV-20	1/17/80	Letter from D. L. Ziemann (NRC) to R. Dietch (SCE), Subject: San Onofre Unit 1 - SEP Topic XV-20.
	3/28/80	Letter from J. G. Hayes (SCE) to D. L. Ziemann (NRC), Subject: San Onofre Unit 1 - SEP Topic XV-20.
XVII	11/20/79	Letter from D. L. Ziemann (NRC) to J. H. Drake (SCE), Subject: Completion of SEP Topic XVII - San Onofre Unit 1.

APPENDIX F

REVIEW OF OPERATING EXPERIENCE FOR SAN ONOFRE NUCLEAR GENERATING STATION, UNIT NO. 1

NSIC-201

Contract No. W-7405-eng-26

Nuclear Safety Information Center

Engineering Technology Division

REVIEW OF THE OPERATING EXPERIENCE HISTORY OF SAN ONOFRE UNIT NO. 1 THROUGH 1981 FOR THE NUCLEAR REGULATORY COMMISSION'S SYSTEMATIC EVALUATION PROGRAM

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REVIEW OF THE OPERATING HISTORY OF SAN ONOFRE UNIT NO. 1 THROUGH 1981

EXECUTIVE SUMMARY

The Systematic Evaluation Program Branch of the Nuclear Regulatory Commission (NRC) is conducting the Systematic Evaluation Program (SEP) for the purpose of determining the safety margins of the design and operation of ten of the older operating commercial nuclear power plants in the United States. These ten plants are being reevaluated in terms of present NRC licensing requirements and regulations. Thus, the SEP is intended:

1. to establish documentation that shows how these ten plants compare with current acceptance criteria and guidelines on significant safety issues and to provide a technical rationale for acceptable departures from these criteria and guidelines,
2. to provide the capability for making integrated and balanced decisions with respect to any required backfitting, and
3. to provide for the early identification and resolution of any potential safety deficiency.

The SEP evaluates specific safety topics based on an integrated review of the overall ability of a plant to respond to certain design basis events including normal operation, transients, and postulated accidents.

As part of the SEP, the NRC contracted with the Oak Ridge National Laboratory to perform operating history reviews. These reviews are intended to augment the SEP's safety topic review and to aid in the determination of priorities for required backfitting during the integrated assessment. Each review includes collection and evaluation of availability and capacity factors, forced shutdowns, forced power reductions, reportable events, environmental events, and radiological release events.

This summary presents the results from the review of the operating experience of the San Onofre Nuclear Generating Station Unit No. 1. San Onofre Unit No. 1 is a Westinghouse Electric Corporation pressurized-water reactor of 436 MW(e) net maximum dependable capacity. The facility is operated by Southern California Edison (SCE) and jointly owned by SCE and San Diego Gas and Electric Company. Bechtel Corporation was the architect/engineer and constructor of the plant. The plant lies entirely within the Camp Pendleton Marine Reservation near San Clemente in San Diego County, California. The plant is operated under provisional operating license DPR-13, issued on March 27, 1967. The date of initial criticality was June 14, 1967 and commercial operation commenced July 17, 1967.

Reactor availability at San Onofre Unit No. 1 for the period 1967 through 1981 was 68.3%. Reactor availability was above 70% except for the years: 1968, 1973, 1977, 1980, and 1981. In these years the unit experienced extended shutdowns. In 1968, the plant was shut down for six months due to a cable fire. A turbine blade failure in 1973 required a two and one-half month shutdown for repair. Reactor coolant pump and steam generator tube inspections, along with steam generator tube plugging required a

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one month shutdown in 1977. Steam generator tube repair also caused an 11 month shutdown for repair beginning in July, 1980, resulting in the relatively low availability achieved in 1980 and 1981.

The operating history review focused on data evaluation which was divided into two segments: (1) evaluation of forced shutdowns and power reductions and (2) evaluation of reportable events. Design basis events (DBEs), which are defined in NRC's *Standard Review Plan*, are failures that initiate system transients and challenge engineered safety features. In the forced shutdown and power reduction segment, the review identified DBEs and recurring events that indicate a potential operating concern. In the reportable event segment, which included environmental events and radiological release events, the review identified significant events and recurring events that indicate a potential operating concern. Significant events were either DBEs or events with a loss of engineered safety function.

Forced Shutdowns and Power Reductions

Of the 154 forced shutdowns and power reductions at San Onofre Unit No. 1 between 1967 and 1981, 27 were identified as design basis events of one of the following types:

1. control rod maloperation (12),
2. turbine trip (5),
3. increase in feedwater flow (4),
4. loss of external electric load (4),
5. loss of normal feedwater flow (1), and
6. reactor coolant pump trip (1).

Of these 27 events, 21 resulted from equipment failure, five from personnel errors and one due to an offsite power disturbance.

San Onofre Unit No. 1 has experienced an average of fewer than two DBEs per year with no discernible trend in the frequency with which DBEs have occurred. Control rod maloperation caused 11 of the 27 DBE events. All 11 involved dropped control rods occurring between 1967 and 1977, with 4 events occurring in 1968 and 3 in 1977. The problem has not occurred since 1977.

Reportable Events

In the reportable event segment of the operating review of San Onofre Unit No. 1, 327 events were examined. From 1967 through 1974, an average of 17 events per year was recorded while from 1975 to 1981, the average was 27 events. The increasing number of events reported can be attributed in part to events concerning steam generator and condenser tube leakage.

The cause of the majority of the reportable events at San Onofre Unit No. 1 was inherent equipment failure (60%). Human error (including administrative, design, fabrication, installation, maintenance and operator error) caused another 35% of the events. Other causes including weather, minor earthquakes, and offsite brush fires accounted for the remaining 5% of the events.

Of the 237 events reviewed, 23 were identified as significant, and are categorized as:

- loss of safety injection system function (3),
- loss of salt water cooling flow (1),
- loss of offsite power (5),
- loss of emergency AC power supply (3),
- feedwater supply transients (3),
- cable tray fires (2),
- loss of boric acid injection path (2),
- instrumentation channels fail due to flooding (2), and
- turbine overspeed events (2).

The first two types of significant events are discussed in this summary.

Two potential losses of safety injection function and one failure to actuate on demand have occurred at San Onofre Unit No. 1. In 1967, one month prior to power operation, both safety injection pumps declared inoperable. Moisture penetration of the motor windings caused both pumps to fail megger testing. The licensee sealed openings to prevent reoccurrence.

In 1975, SCE reported a potential single failure that would cause loss of at least a portion of the flow from both safety injection trains. Failure of either of the two safety injection pumps' discharge valves could allow safety injection flow from both pumps to be routed to the steam generator rather than to the reactor coolant system. Administrative controls were established to protect against such a failure and subsequently extensive modifications corrected the problem.

On September 3, 1981, a voltage regulator failure caused erratic instrument readings leading to a manual reactor trip. In the transient following the trip, safety injection actuation occurred due to a decrease in reactor coolant system pressure. However, operator surveillance discovered that the safety injection valves both failed to open. Since the RCS pressure never dropped to the discharge pressure of the safety injection pumps, SIS flow would not have occurred even if the valves had opened. This event represents failure of both trains of safety injection. A design evaluation and further testing determined that the valves would not open against the design differential pressure. Design changes were evaluated and implemented to correct the problem. Augmented surveillance testing of these valves was also instituted.

On March 10, 1980, while operating at 100% power, San Onofre Unit No. 1 experienced a complete loss of flow from the salt water cooling system. The salt water cooling system is the ultimate heat sink for the component cooling water (CCW) system, which serves to cool certain safety-related equipment. The event involved a triple failure consisting of (1) shearing of the south salt water cooling pump shaft, (2) failure to open of the north salt water cooling pump discharge valve, and (3) failure of the auxiliary salt water cooling pump air priming system. As a result, the plant was totally without salt water cooling flow for 10 min, at which time an operator cross connected the screen wash pumps to provide salt water flow to a CCW heat exchanger. This limited the CCW temperature rise (from 66 to 82°F in the 10 min) and brought the equilibrium temperature down to 70°F. The screen wash pumps are not classified as safety-related equipment.

At 41 min into the event, the auxiliary salt water cooling pump was restored to service and flow through it to an in-service CCW heat exchanger began 17 min later. Throughout the event, the unit remained at or near full power. A power reduction was initiated at first, but then stopped with only a 3 MW power decrease. The NRC cited the plant for two technical specification violations in this event.

Although not in the original time frame for this examination of operating experience, three more events involving the salt water cooling system occurred in 1982 and are discussed here. On May 13, 1982, two more complete losses of salt water cooling system flow occurred during maintenance. During these events, the unit was in cold shutdown. The events were due to flooding of the intake structure caused by inadequate maintenance procedures. On August 13, 1982, flow from the operable north salt water cooling pump was diverted through the idle south pump. This occurred due to unexpected opening of the south pump's discharge valve. An operator immediately closed the valve and no observable reactor coolant system temperature increase occurred. On August 19, 1982, with the south saltwater cooling pump still out of service, the north pump had to be removed from service due to a smoking motor bearing. Necessary flow to the CCW heat exchangers was maintained by the auxiliary salt water cooling pump, which although connected to an emergency bus, does not meet all seismic qualifications.

Recurring Events

In addition to individual events considered significant, there are five areas in which problems have recurred at San Onofre over portions of the operating history. The problem areas were:

- inverter failures and losses of vital bus power,
- steam generator leaks,
- dilution of primary coolant,
- tsunami gate closure, and
- erroneous control rod indications.

There have been 21 occurrences of momentary loss of vital power, causing 5 shutdowns and 9 power reductions. These events have occurred from 1969 to 1979, with all but one of the vital power interruptions due to inverter failures.

After the first 5 years of operation, steam generator tube leakage became a problem. Beginning in 1972, steam generator tube leaks began recurring, causing 9 forced shutdowns and 17 reportable events. Steam generator tube leakage problems and required repairs were the reason for the 11 month shutdown that began in July 1980.

On four occasions, dilution of the primary coolant system resulted in reduced boron concentration. The first of these events was due to secondary to primary system leakage during tube plugging. Another secondary to primary leakage that resulted in boron dilution was caused by a leaking block valve in the feedwater system. The remaining two dilution events occurred due to water being added to the primary system during decontamination of equipment.

On three occasions, San Onofre has experienced inadvertent closure of the tsunami gate, the salt water intake stop gate. These events occurred in 1967, 1968, and 1969 and were due to a shorted limit switch, rupture of the accumulator reservoir tank, and failure of the gate's annular bolts, respectively.

Conclusions

For this analysis of San Onofre Unit No. 1 operating history, 154 shutdowns and power reductions were reviewed along with 327 reportable events and other miscellaneous documentation concerning the operation of San Onofre Unit No. 1. The objective was to identify those areas of plant operation that have affected plant safety.

This review identified three areas of concern for San Onofre Unit No. 1. The first concern involves the safety injection system. The two potential failures and one failure on demand for the safety injection system represent unacceptable response by an engineered safety feature.

The total loss of salt water cooling flow in 1980 would have been a more serious event if it had occurred during the early stages of residual heat removal operation. The continued problems with the system make the salt water cooling system a second area of concern identified in this review.

Finally, the recurring problems with vital bus power caused by inverter failures is of concern. Although single inverter failures are of limited consequence, the number of failures experienced at San Onofre provides the potential for concurrent failures.

Reference

1. Nuclear Regulatory Commission, "Accident Analysis for the Review of Safety Analysis Reports for Nuclear Power Plants," Chap. 15 of *Standard Review Plan*, NUREG-0800 (July 1981).

REVIEW OF THE OPERATING EXPERIENCE HISTORY OF SAN ONOFRE UNIT NO. 1 THROUGH 1981 FOR THE NUCLEAR REGULATORY COMMISSION'S SYSTEMATIC EVALUATION PROGRAM

1. SCOPE OF REVIEW

The assessment of the operating experience review for San Onofre Unit No. 1 covered the time from initial criticality through 1981. The data collection and evaluation included the following aspects of operation: availability and capacity factors, forced shutdowns and power reductions, reportable events, events of enviromental importance and radioactivity releases, and evaluation of the operating experience in total. Tables at the end of Chap. 1 show the codes assigned to operational aspects of forced shutdowns, power reductions, and reportable events. These codes are used in the reporting of data collected during the review of operating experience.

1.1 Availability and Capacity Factors

Both reactor and unit availability factors were compiled for all years. Starting with 1974, the unit capacity factors using the design electrical rating (DER) in net megawatts (electric) and the maximum dependable capacity (MDC) in net megawatts (electric) were compiled as well. Data for the capacity factors were not available from earlier years.

The two availability and two capacity factors are defined as follows:

1. reactor availability =

$$\frac{\text{hours reactor critical + reactor reserve shutdown hours}}{\text{period hours}} \times 100\ ,$$

2. unit availability =

$$\frac{\text{hours generator on line + unit reserve shutdown hours}}{\text{period hours}} \times 100\ ,$$

3. $\text{unit capacity (DER)} = \dfrac{\text{net electrical energy generated}}{\text{period hours x DER net}} \times 100\ ,$

4. $\text{unit capacity (MDC)} = \dfrac{\text{net electrical energy generated}}{\text{period hours x MDC net}} \times 100\ .$

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Reserve shutdown hours are the amounts of time the reactor is not critical or the unit is shutdown for administrative or other similar reasons when operation could have been continued.

1.2 Review of Forced Shutdowns and Power Reductions

Forced shutdowns and power reductions were reviewed, and data were collected on each incident. Scheduled shutdowns for refueling and maintenance were not included in the review. However, if a utility had a refueling outage scheduled, the plant experienced a shutdown as a result of an abnormal event prior to the scheduled refueling, the utility reported that the refueling was being rescheduled to coincide with the current shutdown, and the utility reported the cause of the shutdown as refueling, then this shutdown was considered as forced. Only that portion of the outage time concerned with the abnormal event, not the refueling time, was included in the compilations.

The power reductions were included to provide information and details that may have been associated with a previous or subsequent shutdown. The power reductions are included in the proper chronological sequence with the shutdowns in the data tables for the forced shutdowns and power reductions (see Appendixes).

The following data were compiled annually for the forced shutdowns and power reductions:

1. date of occurrence,
2. duration (hours),
3. power level (percent),
4. notation of whether the shutdowns were also reportable events [e.g., a licensee event report (LER) or abnormal occurrence report (AOR)],
5. summary description of events associated with the forced shutdown or power reduction,
6. cause of shutdown (Table 1.1),
7. method of shutdown (Table 1.1),
8. system taken from NUREG-0161 (Ref. 1) that was directly involved with the shutdown or power reduction (Table 1.2),
9. component directly involved with the shutdown or power reduction (Table 1.3), and
10. categorization of the shutdown or power reduction.

Each shutdown or power reduction was placed in one of two sets of significance categories. The shutdowns and power reductions were first evaluated against criteria for design-basis events (DBEs) as described in Chap. 15 of the *Standard Review Plan.*[2] If the shutdown or power reduction could not be categorized as a design-basis initiating event, then it was placed in one of a series of Nuclear Safety Information Center (NSIC) categories. For further discussions of the two sets of significance categories, use of the categories, and a listing of them, see Sect. 3.1.

The listings for the cause, shutdown method, system involved, and component involved along with their respective codes are those used in the NUREG-0020 series[3] ("Gray Books") on shutdowns. Note that the information

Table 1.1. Codes for causes of forced shutdown or power reduction and methods of shutdown

	Causes
A	Equipment failure
B	Maintenance or testing
C	Refueling
D	Regulatory restriction
E	Operator training and license exams
F	Administrative
G	Operational error
H	Other
	Methods
1	Manual
2	Manual scram
3	Automatic scram
4	Continuation
5	Load reduction
9	Other

Table 1.2. Codes for systems involved with the forced shutdown, power reduction, or reportable event

System	Code
Reactor	RX
Reactor vessel internals	RA
Reactivity control systems	RB
Reactor core	RC
Reactor coolant and connected systems	CX
Reactor vessels and appurtenances	CA
Coolant recirculation systems and controls	CB
Main steam systems and controls	CC
Main steam isolation systems and controls	CD
Reactor core isolation cooling systems and controls	CE
Residual heat removal systems and controls	CF
Reactor coolant cleanup systems and controls	CG
Feedwater systems and controls	CH
Reactor coolant pressure boundary leakage detection systems	CI
Other coolant subsystems and their controls	CJ
Engineered safety features	SX
Reactor containment systems	SA
Containment heat removal systems and controls	SB
Containment air purification and cleanup systems and controls	SC
Containment isolation systems and controls	SD
Containment combustible control systems and controls	SE
Emergency core cooling systems and controls	SF
Core reflooding system	SF-A
Low-pressure safety injection system and controls	SF-B
High-pressure safety injection system and controls	SF-C
Core spray system and controls	SF-D
Control room habitability systems and controls	SG
Other engineered safety feature systems and their controls	SH
Containment purge system and controls	SH-A
Containment spray system and controls	SH-B
Auxiliary feedwater system and controls	SH-C
Standby gas treatment systems and controls	SH-D
Instrumentation and controls	IX
Reactor trip systems	IA
Engineered safety feature instrument systems	IB
Systems required for safe shutdown	IC
Safety-related display instrumentation	ID
Other instrument systems required for safety	IE
Other instrument systems not required for safety	IF

Table 1.2 (continued)

System	Code
Electric power systems	EX
Offsite power systems and controls	EA
AC onsite power systems and controls	EB
DC onsite power systems and controls	EC
Onsite power systems and controls (composite ac and dc)	ED
Emergency generator systems and controls	EE
Emergency lighting systems and controls	EF
Other electric power systems and controls	EG
Fuel storage and handling systems	FX
New fuel storage facilities	FA
Spent-fuel storage facilities	FB
Spent-fuel pool cooling and cleanup systems and controls	FC
Fuel handling systems	FD
Auxiliary water systems	WX
Station service water systems and controls	WA
Cooling systems for reactor auxiliaries and controls	WB
Demineralized water makeup systems and controls	WC
Potable and sanitary water systems and controls	WD
Ultimate heat sink facilities	WE
Condensate storage facilities	WF
Other auxiliary water systems and controls	WG
Auxiliary process systems	PX
Compressed air systems and controls	PA
Process sampling systems	PB
Chemical, volume control, and liquid poison systems and controls	PC
Failed-fuel detection systems	PD
Other auxiliary process systems and controls	PE
Other auxiliary systems	AX
Air conditioning, heating, cooling, and ventilation systems and controls	AA
Fire protection systems and controls	AB
Communication systems	AC
Other auxiliary systems and controls	AD
Steam and power conversion systems	HX
Turbine-generators and controls	HA
Main steam supply systems and controls (other than CC)	HB
Main condenser systems and controls	HC
Turbine gland sealing systems and controls	HD
Turbine bypass systems and controls	HE

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Table 1.2 (continued)

System	Code
Circulating water systems and controls	HF
Condensate cleanup systems and controls	HG
Condensate and feedwater systems and controls (other than CH)	HH
Steam generator blowdown systems and controls	HI
Other features of steam and power conversion systems (not included elsewhere)	HJ
Radioactive waste management systems	MX
Liquid radioactive waste management systems	MA
Gaseous radioactive waste management systems	MB
Process and effluent radiological monitoring systems	MC
Solid radioactive waste management systems	MD
Radiation protection systems	BX
Area monitoring systems	BA
Airborne radioactivity monitoring systems	BB
Other	XX
Not applicable	ZZ

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Table 1.3. Components involved with the forced shutdown or power reduction

Component type	Including
Accumulators	Scram accumulators Safety injection tanks Surge tanks
Air dryers	
Annunciator modules	Alarms Bells Buzzers Claxons Horns Gongs Sirens
Batteries and chargers	Chargers Dry cells Wet cells Storage cells
Blowers	Compressors Gas circulators Fans Ventilators
Circuit closers/interruptors	Circuit breakers Contactors Controllers Starters Switches (other than sensors) Switchgear
Control rods	Poison curtains
Control rod drive mechanisms	
Demineralizers	Ion exchangers
Electrical conductors	Bus Cable Wire
Engines, internal combustion	Butane engines Diesel engines Gasoline engines Natural gas engines Propane engines
Filters	Strainers Screens
Fuel elements	
Generators	Inverters
Heaters, electric	

Table 1.3 (continued)

Component type	Including
Heat exchangers	Condensers Coolers Evaporators Regenerative heat exchangers Steam generators Fan coil units
Instrumentation and controls	
Mechanical function units	Mechanical controllers Governors Gear boxes Varidrives Couplings
Motors	Electric motors Hydraulic motors Pneumatic (air) motors Servo motors
Penetrations, primary containment air locks	
Pipes, fittings	
Pumps	
Recombiners	
Relays	
Shock suppressors and supports	
Transformers	
Turbines	Steam turbines Gas turbines Hydro turbines
Valves	Valves Dampers
Valve operators	
Vessels, pressure	Containment vessels Dry wells Pressure suppression Pressurizers Reactor vessels

listed under the "System involved" column in the data tables in Appendix A.1 indicates (1) a general classification of systems (fully written out) and (2) a specific system, which is coded with two letters, within the general classification.

1.3 Review of Reportable Events

The operating events as reported in LERs and LER predecessors [e.g., AOs, unusual event reports, reportable occurrences (ROs)] were reviewed. These types of reportable events were retrieved from the NSIC computer file. Approximately six years ago, operating experience information for operating nuclear power plants was input to the NSIC file for the period of time before LERs were reviewed. Any documents that contained LER-type information (such as equipment failures or abnormal events) were coded or indexed so that they could be retrieved in the same manner as an LER. Primarily, this involved various types of operating reports and general correspondence for the late 1960s and early 1970s.

The following information was recorded for each reportable event reviewed:

1. LER number or other means of identification of report type,
2. NSIC accession number (a unique identification number assigned to each document entered into the NSIC computer file),
3. date of the event,
4. date of the report or letter transmitting the event description,
5. status of the plant at the time of the occurrence (Table 1.4),
6. system involved with the reportable event (Table 1.2),
7. type of equipment involved with the reportable event (Table 1.5),
8. type of instrument involved with the reportable event (Table 1.5),
9. status of the component (equipment) at the time of the occurrence (Table 1.4),
10. abnormal condition associated with the reportable event (e.g., corrosion, vibration, leak) (Table 1.6),
11. cause of the reportable event (Table 1.4), and
12. significance of the reportable event.

As a step in the evaluation process, each reportable event was screened using the criteria further discussed in Sect. 3.2.

Note that in the tables of reportable events in Appendix A.2 for San Onofre Unit 1, comments and/or details on the events were included.

1.4 Events of Environmental Importance and Releases of Radioactivity

Any significant or recurring environmental problems were summarized based on the review of forced shutdowns, power reductions, reportable events (environmental LERs), and operating reports. Routine radioactivity releases were tabulated as well, and releases that resulted in reportable events were reviewed and are discussed in Sect. 4.5.1.4.

Table 1.4. Codes for data collected on plant status, component status, and cause of reportable events

Code	Plant status	Component status	Cause of reportable event
A	Construction	Maintenance and repair	Administrative error
B	Operation	Operation	Design error
C	Refueling	Testing	Fabrication error
D	Shutdown		Inherent error
E			Installation error
F			Lightning
G			Maintenance error
H			Operation error
I			Weather

Table 1.5. Codes for equipment and instruments involved in reportable events

Code		Code	
	Equipment		
A	Accumulator	W	Internal combustion engine
B	Air drier	X	Motor
C	Battery and charger	Y	Nozzle
D	Bearing	Z	Pipe and pipe fitting
E	Blower and dampers	AA	Power supply
F	Breaker	BB	Pressure vessel
G	Cables and connectors	CC	Pressurizer
H	Condenser	DD	Pump
I	Control rod	EE	Recombiner
J	Control rod drive	FF	Seal
K	Cooling tower	GG	Shock absorber
L	Crane	HH	Solenoid
M	Demineralizer	II	Steam generator
N	Diesel generator	JJ	Storage container
O	Fastener	KK	Support structure
P	Filter/screen	LL	Transformer
Q	Flange	MM	Tubing
R	Fuel element	NN	Turbine
S	Fuse	OO	Valve
T	Generator	PP	Valve, check
U	Heat exchanger	QQ	Valve operator
V	Heater		
	Instrumentation		
A	Alarm	L	Power range instrument
B	Amplifier	M	Pressure sensor
C	Electronic function unit	N	Radiation monitor
D	Failed fuel detection instrument	O	Recorder
E	Flow sensor	P	Relay
F	In-core instrument	Q	Seismic instrument
G	Indicator	R	Solid state device
H	Intermediate range instrument	S	Start-up range instrument
I	Level sensor	T	Switch
J	Meteorological instrument	U	Temperature sensor
K	Position instrument		

Table 1.6. Codes used for reportable events—abnormal conditions

	Mechanical
AA	Normal wear/aging/end of life: expected effect of normal usage
AB	Excessive wear/clearance: component (especially a moving component) experiences excessive wear or too much clearance or gap exists because of overuse, lack of lubrication
AC	Deterioration/damage: component is no longer at an acceptable level of quality (e.g., high temperature causes rubber seals to chemically break down or deteriorate, insulation breaks down)
AD	Break/shear: structural component physically breaks apart (not when something "breaks down")
AE	Warp/bend/deformation: shape of component is physically distorted
AF	Collapse: tank or compartment has an external pressure exerted that results in deformation
AG	Seize/bind/jam: component has inhibited movement caused by crud, foreign material, mechanical bonding, another component
AH	Excessive mechanical loads: mechanical load exceeds design limits
AI	Mechanical fatigue: failure due to repeated stress
AJ	Impact: the result of the force of one object striking another
AK	Improper lubrication: insufficient or incorrect lubrication
AL	Missing/loose: component is missing from its proper place or is loose or has undesired free movement
AM	Wrong part: incorrect component installed in a piece of equipment
AN	Wrong material: incorrect material used during fabrication or installation
AO	Weld-related failure: failure caused by defective weld or located in the heat-affected zone
AP	Vibration other than flow induced: vibration from any cause other than fluid flow
AQ	Crud buildup: buildup of foreign material such as dust, sticks, trash (not corrosion or boron precipitation)
AR	Corrosion/oxidation: unanticipated attack
AS	Dropped: component is dropped (includes control rod that is "dropped" into core)
AT	Leak, internal, within system: leak from one part of a system to another part of the same system
AU	Leak, internal, between systems: leak from one system to a different system
AV	Crack: defect in a component does not result in a leak through the wall

Table 1.6 (continued)

AW	Leak, external: defect in a component results in a leak from the system that is contained in an onsite building
AX	Leak to environment: leak not resulting from a cracked or broken component
AY	Was opened/transfers open: component is/was opened by error or spuriously opens
AZ	Was closed/transferred closed: component is/was wrongly closed by error or spuriously closes
BA	Fails to open: component is in the closed state and fails to open on demand (e.g., the circuit breaker "fails to open" when an overcurrent occurs)
BB	Fails to close: component is in the open state and fails to close on demand
BC	Malposition or maladjustment: component is out of desired position (e.g., normally open valve is closed) or adjusted improperly (not for instrument drift or out of calibration)
BD	Failure to start/turn on: component fails to start on demand
BE	Stopped/failed to continue to run: component fails to continue running when it has previously started
BF	Tripped: component automatically trips on or off (desired or undesired) (e.g., the turbine tripped because of overspeed, the circuit breaker tripped because of overspeed, or the circuit breaker tripped because of overload)
BG	Deenergized/power removed: component on system loses its driving potential but not necessarily electrical power [e.g., (1) a fuse blows and there is no power to a sensor, and the sensor is deenergized; (2) a valve closes off the steam supply to a turbine, and the turbine has no driving power]
BH	Energized/power applied: component or system gains its driving potential but not necessarily electrical power (e.g., valve is opened allowing steam to turn a turbine)
BI	Unacceptable response time: component does not respond to a demand within a desired time frame but does not otherwise fail (e.g., a diesel generator fails to come to full speed within the time constraint)
BJ	High pressure: higher than normal or desired pressure exists in a component or system (does not include instrument misindications)

Table 1.6 (continued)

BK	Low pressure: lower than normal or desired pressure exists in a component or system (does not include instrument misindication)
BL	High temperature: component experiences a higher than normal or desired temperature
BM	Low temperature: component (or system) experiences a lower than normal or desired temperature
BN	Freezing: fluid medium (e.g., water) freezes in or on a component
BO	Excessive thermal cycling: frequent changes in temperature that could result in metal fatigue or cracking
BP	Unacceptable heatup/cooldown rate: heatup or cooldown rate exceeds limits
BQ	Thermal transient: system experiences an undesired or unstable thermal transient or thermal change
BR	Excessive number of pressure cycles: system experiences an undesired number of significant pressure changes (e.g., pressure pulses as from a positive displacement pump)
BS	High level/volume: higher than normal or desired level or volume exists (actual or potential) in a component, such as tank or sump, or area, such as auxiliary building (not for instrument misindication)
BT	Low level/volume: lower than normal or desired level or volume exists in a component (not for instrument misindication)
BU	Abnormal concentration/pH: an abnormal (either high or low) concentration of a chemical or reagent exists in a fluid system or an abnormal pH exists (does not include abnormal boron concentrations)
BV	Abnormal boron concentration: process system control rod has an abnormal boron concentration from burnup, dilution, or overaddition
BW	Overspeed: speed in excess of design limits
BX	Cladding failure: cladding of a component fails (e.g., the cladding of a fuel pellet is breached, and radioactive fuel leaks out)
BY	Burning/smoking: component is on fire or smoking
BZ	Engaged: component engages or meshes (this is not to be used when a component binds or becomes stuck or jammed)
CA	Disengaged/uncoupled: component disengages, loses required friction, or is no longer meshed (as in gears); for example, the clutch on the motor disengages from the shaft (this should not be used for dropped control rods)

Table 1.6 (continued)

Electric/instruments

EA	Excessive electrical loads: electrical loads exceed design rating
EB	Overvoltage/undercurrent: component failure produces an overvoltage/undercurrent condition other than open circuits
EC	Undervoltage/overcurrent: component failure produces an undervoltage/overcurrent condition other than shorts
ED	Short circuit/arcing/low impedance: electrical component shorts or arcs in the circuit or has a low impedance including shorts to ground
EE	Open circuit/high impedance/bad electrical contact: electrical component has a structural break, or electrical contacts fail to contact and fail to pass the desired current
EF	Erratic operation: component (especially electrical or instrument) behaves erratically or inconsistently (if an instrument produces a bad but constant signal, use "EG"; if an instrument produces an inconsistent signal use "EF")
EG	Erroneous/no signal: electrical component or instrument produces an erroneous signal or gives no signal at all (not for out-of-calibration error)
EH	Drift: a change in a setting caused by aging or change of physical characteristics (does not include personnel errors or a physical shift of a component)
EI	Out of calibration: component (particularly instruments) become out of adjustment or calibration (does not include drift)
EJ	Electromagnetic interference: abnormal indication or action resulting from unanticipated electromagnetic field
EK	Instrument snubbing: dampening of pulsating signals to an instrument

Hydraulic

HA	High flow: higher than normal or desired flow exists in a component/system (does not include instrument misindication (see code EG)
HB	Low flow: lower than normal or desired flow exists in a component/system (does not include instrument misindication)
HC	No flow or impulse: fluid flowing through a pipe, filter, orifice, or trench or the fluid in an impulse line (e.g., instrument sensing line) is blocked completely or decreased due to some foreign material, crud, closed (either partially or completely) valve or damper, or insufficient flow area

Table 1.6 (continued)

HD	Flow induced vibration
HE	Cavitation
HF	Erosion
HG	Vortex formation
HH	Water hammer
HI	Pressure pulse/surge
HJ	Air/steam binding
HK	Loss of pump section
HL	Boron precipitation
	Other
OA	Declared inoperable: component or system is declared inoperable as required by Technical Specifications but may be capable of partially or completely performing its desired duties when requested (a component/system that is completely failed should not use this code)
OB	Flux anomaly: flux characteristics of the reactor core are not as required or desired (e.g., flux spike due to xenon burnout)
OC	Test not performed: operator or test personnel fails to perform a required test within the required period
OD	Radioactivity contamination: component, system, or area becomes more radioactive than desired or expected
OE	Temporary modification: an installation intended for short term use (usually this is for maintenance or modification of installed equipment)
OF	Environmental anomaly
OG	Airborne release
OH	Waterborne release
OI	Operator communication
OJ	Operator incorrect action
OK	Procedure or record error

1.5 Evaluation of Operating Experience

The operating history of the plants was evaluated based on a review that involved screening, categorizing, and compiling data. Judgments and conclusions were made regarding safety problems, operations, trends (recurring problems), or potential safety concerns. Events were analyzed to determine their safety significance from the information provided through the various operating reports and the review process. The final safety analysis reports provided specific plant and equipment details when necessary.

From the information provided through the various operating reports and the review process, events were analyzed to determine their safety significance, using the final safety analysis reports to provide specific plant and equipment details when necessary.

2. SOURCES OF INFORMATION USED IN THE REVIEW

Several sources of information including periodic (annual, quarterly, and monthly) NRC publications were used in the review. Some sources contained information relative to more than one area within the scope of the review.

2.1 Availability and Capacity Factors

The availability and capacity factors were either extracted or calculated from data given in the Gray Books[3] from 1974 through 1981 (the first Gray Book was issued in May 1974). Prior to 1974, annual or semiannual reports were used to compile availability factors only.

2.2 Forced Reactor Shutdowns and Power Reductions

Review of the forced power reductions involved checking the following sources for accuracy and completeness of details.

1. *Nuclear Power Plant Operating Experience for 19XX*, for the years 1973-1980 (Refs. 4-10). The report for 1981 has not been published.
2. NUREG-0020 series[3] (Gray Books).
3. Annual or semiannual reports of the San Onofre Unit No. 1 plant from the time of startup through 1977. For 1977 through 1981, monthly operating reports were used because the utilities were no longer required to file annual reports. The review of power reductions involved primarily the annual, semiannual, and monthly reports.

2.3 Reportable Events

The NSIC computer file of LERs was the primary source of information in reviewing reportable events. Material on the NSIC computer file consists of the appropriate bibliographic material, title, 100-word abstract, and keywords. When additional information on the event was needed, the original LER (or equivalent) was consulted by examining (1) those full-sized copies on file at NSIC (for the years 1976-1981); (2) the microfiche file of docket material at NSIC; or (3) the appropriate operating report (semiannual, annual, or monthly).

2.4 Environmental Events and Releases of Radioactivity

Events of environmental importance were obtained as a result of conducting the overall review of the plant's operating history, and the sources of information involve all types of documents listed thus far.

The data for radioactivity releases were compiled primarily from *Radioactive Materials Released from Nuclear Power Plants — Annual Report*

1977 (Ref. 11). This report presents year-by-year comparisons for plants in a number of different categories (such as solid, gas, liquid, noble gas, and tritium). Data for 1978 were taken from *Radioactive Materials Released from Nuclear Power Plants - Annual Report 1978* (Ref. 12). Data for 1979 through 1981 were compiled from the annual environmental reports submitted by the licensees.

3. TECHNICAL APPROACH FOR EVALUATIONS OF OPERATING HISTORY

Forced shutdowns (and power reductions) and reportable events were the two areas focused on in the evaluation of the operating history of the plants of interest. Given the large number of both forced shutdowns and reportable events, it was necessary to develop consistent review procedures that involved screening and categorizing of both type occurrences. After the events were screened and categorized, the study then assessed the safety significance of the events and analyzed the categories of events for various trends and recurring problems.

The review approach with respect to operational events (forced shutdowns and reportable occurrences) consisted primarily of a three-step process: (1) compilation of information on the events, (2) screening of the events for significance using selected criteria and guidelines, and (3) evaluation of the significance and importance of the events from a safety standpoint. The evaluations were to determine those areas where safety problems existed in terms of systems, equipment, procedures, and human error.

Shutdowns were evaluated against the DBEs found in Chap. 15 of the *Standard Review Plan.*[3] The DBEs are those postulated disturbances in process variables or postulated malfunctions or failures of equipment that the plants are designed to withstand and that licensees are expected to analyze and include in safety analysis reports (SARs). The SAR provides the opportunity for the effects of anticipated process disturbances and postulated component failures to be examined to determine their consequences and to evaluate the capability built into the plant to control or accommodate such failures and situations (or to identify the limitations of expected performance).

The intent is to organize the transients and accidents considered by the licensee and presented in the SAR in a manner that will:

1. ensure that a sufficiently broad spectrum of initiating events has been considered,
2. categorize the initiating events by type and expected frequency of occurrence so that only the limiting cases in each group need to be quantitatively analyzed, and
3. permit the consistent application of specific acceptance criteria for each postulated initiating event.

Each postulated initiating event is to be assigned to one of the following categories:

1. increase in heat removal by the secondary system (turbine plant),
2. decrease in heat removal by the secondary system (turbine plant),
3. decrease in reactor coolant system flow rate,
4. anomalies in reactivity and power distribution,
5. increase in reactor coolant inventory,
6. decrease in reactor coolant inventory,
7. radioactive release from a subsystem or component, or
8. anticipated transients without scram.

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Those shutdowns identified as design-basis initiating events were categorized as such. If the shutdown was not a DBE, then it was assigned a category from a list developed by NSIC to indicate the nature and type of error or failure. The NSIC categories for shutdowns not caused by DBEs were examined as part of a trends analysis.

Reportable events were screened using the criteria presented in Sect. 3.2 and were categorized according to their significance. The information collected on the reportable events was used to analyze trends for all reportable events, both significant and not significant.

3.1 Significant Shutdowns and Power Reductions

For the purposes of compiling information and evaluation, power reductions were treated in the same manner as forced shutdowns.

3.1.1 Criteria for significant shutdowns and power reductions

As indicated previously, the occurrences identified as DBEs were used as criteria to categorize and note significant shutdowns. These events are listed in Table 3.1 as they are found in Chap. 15 of the *Standard Review Plan.*[3]

3.1.2 Use of criteria for determining significant shutdowns and power reductions

Generic design-basis initiating events such as "increase in heat removal by the secondary system" or "decrease in reactor coolant system flow rate," were used as primary flags for reviewing the forced shutdowns (and power reductions). Once the generic type of event was identified, the particular initiating event was determined from the details associated with the shutdown. For example, if the reactor shuts down because of an increase in heat removal because a feedwater regulator valve failed open, the shutdown is a generic type 1 DBE. Specifically, based on the initiating event (valve failed open), it is a 1.2 DBE — "feedwater system malfunction that results in an increase in feedwater flow." Some shutdowns were readily identifiable as specific DBEs, such as tripping of a main coolant pump, a 3.1 DBE. Once categorized as a DBE, the shutdown was considered significant regardless of the resulting effect on the plant (because a DBE had been initiated).

The review of events assumed that loss of flow from one feedwater loop was sufficient to qualify as a 2.7 DBE — "loss of normal feedwater flow."

3.1.3 Non-DBE shutdown and power reduction categorization

Those shutdowns that were not DBEs were assigned NSIC categories (Table 3.2) to provide more information on the failure or error associated with the shutdown. With these categories, more specific types of errors

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Table 3.1. Initiating event descriptions for DBEs as listed in Chap. 15, *Standard Review Plan* (Revision 3)

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1. Increase in heat removal by the secondary system
    - 1.1 Feedwater system malfunction that results in a decrease in feedwater temperature
    - 1.2 Feedwater system malfunction that results in an increase in feedwater flow
    - 1.3 Steam pressure regulator malfunction or failure that results in increasing steam flow
    - 1.4 Inadvertent opening of a steam generator relief or safety valve
    - 1.5 Spectrum of steam system piping failures inside and outside of containment in a pressurized-water reactor (PWR)
    - 1.6 Startup of idle recirculation pump[a]
    - 1.7 Inadvertent opening of bypass resulting in increase in steam flow[a]
2. Decrease in heat removal by the secondary system
    - 2.1 Steam pressure regulator malfunction or failure that results in decreasing steam flow
    - 2.2 Loss of external electric load
    - 2.3 Turbine trip (stop valve closure)
    - 2.4 Inadvertent closure of main steam isolation valves
    - 2.5 Loss of condenser vacuum
    - 2.6 Coincident loss of onsite and external (offsite) ac power to the station
    - 2.7 Loss of normal feedwater flow
    - 2.8 Feedwater piping break
    - 2.9 Feedwater system malfunctions that result in an increase in feedwater temperature[a]
3. Decrease in reactor coolant system flow rate
    - 3.1 Single and multiple reactor coolant pump trips
    - 3.2 Boiling-water reactor (BWR) recirculation loop controller malfunction that results in decreasing flow rate
    - 3.3 Reactor coolant pump shaft seizure
    - 3.4 Reactor coolant pump shaft break
4. Reactivity and power distribution anomalies
    - 4.1 Uncontrolled control rod assembly withdrawal from a subcritical or low-power start-up condition (assuming the most unfavorable reactivity conditions of the core and reactor coolant system), including control rod or temporary control device removal error during refueling
    - 4.2 Uncontrolled control rod assembly withdrawal at the particular power level (assuming the most unfavorable reactivity conditions of the core and reactor coolant system) that yields the most severe results (low power to full power)
    - 4.3 Control rod maloperation (system malfunction or operator error), including maloperation of part length control rods

Table 3.1 (continued)

4.4 Start-up of an inactive reactor coolant loop or recirculating loop at an incorrect temperature.
4.5 A malfunction or failure of the flow controller in a BWR loop that results in an increased reactor coolant flow rate
4.6 Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant of a PWR
4.7 Inadvertent loading and operation of a fuel assembly in an improper position
4.8 Spectrum of rod ejection accidents in a PWR
4.9 Spectrum of rod drop accidents in a BWR

5. Increase in reactor coolant inventory

5.1 Inadvertent operation of emergency core cooling system during power operation.
5.2 Chemical and volume control system malfunction (or operator error) that increases reactor coolant inventory
5.3 A number of BWR transients, including items 1.2 and 2.1–2.6

6. Decrease in reactor coolant inventory

6.1 Inadvertent opening of a pressurizer safety or relief valve in either a PWR or a BWR
6.2 Break in instrument line or other lines from reactor coolant pressure boundary that penetrate containment
6.3 Steam generator tube failure
6.4 Spectrum of BWR steam system piping failures outside of containment
6.5 Loss-of-coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary, including steam line breaks inside of containment in a BWR
6.6 A number of BWR transients, including items 1.3, 2.7, and 2.8

7. Radioactive release from a subsystem or component

7.1 Radioactive gas waste system leak or failure
7.2 Radioactive liquid waste system leak or failure
7.3 Postulated radioactive releases due to liquid tank failures
7.4 Design basis fuel handling accidents in the containment and spent fuel storage buildings
7.5 Spent fuel cask drop accidents

8. Anticipated transients without scram

8.1 Inadvertent control rod withdrawal
8.2 Loss of feedwater
8.3 Loss of ac power
8.4 Loss of electrical load
8.5 Loss of condenser vacuum
8.6 Turbine trip
8.7 Closure of main steam line isolation valves

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[a] These initiating events were added for BWRs to be more specific than DBE events 5.3 and 6.6.

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Table 3.2. NSIC event categories for non-DBE shutdowns

- N 1.0 Equipment failure
  - N 1.1 Failure on demand under operating conditions
    - N 1.1.1 Design error
    - N 1.1.2 Fabrication error
    - N 1.1.3 Installation error
    - N 1.1.4 End of design life/inherent failure/random failure
  - N 1.2 Failure on demand under test conditions
    - N 1.2.1 Design error
    - N 1.2.2 Fabrication error
    - N 1.2.3 Installation error
    - N 1.2.4 End of design life/inherent failure/random failure
- N 2.0 Instrumentation and control anomalies
  - N 2.1 Hardware failure
  - N 2.2 Power supply problem
  - N 2.3 Setpoint drift
  - N 2.4 Spurious signal
  - N 2.5 Design inadequacy (system required to function outside design specifications)
- N 3.0 Non-DBE reductions in coolant inventory (leaks)
  - N 3.1 In primary system
  - N 3.2 In secondary system and auxiliaries
- N 4.0 Fuel/cladding failure (densification, swelling, failed fuel elements as indicated by elevated coolant activity)
- N 5.0 Maintenance error
  - N 5.1 Failure to repair component/equipment/system
  - N 5.2 Calibration error
- N 6.0 Operator error
  - N 6.1 Incorrect action (based on correct understanding on the part of the operator and proper procedures, the operator turned the wrong switch or valve — incorrect action)
  - N 6.2 Action on misunderstanding (based on proper procedures and improper understanding or misinterpretation on the operator's part of what was to be done — incorrect action)
  - N 6.3 Inadvertent action (purpose and action not related, for example, bumping against a switch or instrument cabinet)
- N 7.0 Procedural/administrative error (incorrect operating or testing procedures, incorrect analysis of an event — failure to consider certain conditions in analysis)
- N 8.0 Regulatory restriction
  - N 8.1 Notice of generic event
  - N 8.2 Notice of violation
  - N 8.3 Backfit/reanalysis

Table 3.2 (continued)

- N 9.0 External events
  - N 9.1 Human induced (sabotage, plane crashes into transformer)
  - N 9.2 Environment induced (tornado, severe weather, floods, earthquake)
- N 10.0 Environmental operating constraint as set forth in Technical Specifications

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and failures could be examined through tabular summaries to focus the reviewer's attention on problem areas (safety related or not) that were not revealed by the DBE categories.

The causes (Table 1.1) for non-DBE shutdowns taken from the Gray Books are limited and very general, while NSIC cause categories are more specific. Thus, as an example, the number of Gray Book causes noted as equipment failure should not be expected to equal those identified as equipment failures with the NSIC categories. Other NSIC categories, such as component failure, could be classified as an equipment failure if the only available designations for cause were those listed in the Gray Books.

3.2 Significant Reportable Events

3.2.1 Criteria for significant reportable events

Two groups of criteria were used in determining significant reportable events. The first set of criteria (Table 3.3) indicates those events that are definitely significant in terms of safety; they are termed significant. The second set of criteria (Table 3.4) indicates events that may be of potential concern. These events, which might require additional information or evaluation to determine their full implication, were noted as conditionally significant.

3.2.2 Use of criteria for determining significant reportable events

The reportable events were all reviewed, applying the two sets of criteria for significance rather liberally. A number of significant events and conditionally significant events were noted. The events initially identified as significant or conditionally significant were analyzed and evaluated further based on (1) engineering judgment; (2) the systems, equipment, or components involved; or (3) whether the safety of the plant was compromised. The final evaluation for significance considered whether a DBE was initiated or whether a safety function was compromised so that the system as designed could not mitigate the progression of events. Thus, the number of events finally categorized as significant was reduced considerably by these steps in the review process.

3.2.3 Reportable events that were not significant

Those reportable events not identified as significant or conditionally significant were categorized as not significant (with an "N" in the significance column of the coding sheets in the appendixes). These events and the events rejected during the additional review step were further reviewed by compiling a tabular summary of the systems to detect trends and recurring problems (Table 1.4 provides a listing of the systems).

Table 3.3. Reportable event criteria — significant

Category of significance	Event description
S1	Two or more failures occur in redundant systems during the same event
S2	Two or more failures due to a common cause occur during the same event
S3	Three or more failures occur during the same event
S4	Component failures occur that would have easily escaped detection by testing or examination
S5	An event proceeds in a way significantly different from what would be expected
S6	An event or operating condition occurs that is not enveloped by the plant design bases
S7	An event occurs that could have been a greater threat to plant safety with (1) different plant conditions, (2) the advent of another credible occurrence, or (3) a different progression of occurrences
S8	Administrative, procedural, or operational errors are committed that resulted from a fundamental misunderstanding of plant performance or safety requirements
S9	Other (explain)

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Table 3.4. Reportable event criteria — conditionally significant

Category of conditional significance	Event description
C1	A single failure occurs in a nonredundant system
C2	Two apparently unrelated failures occur during the same event
C3	A problem results in an offsite radiation release or exposure to personnel
C4	A design or manufacturing deficiency is identified as the cause of a failure or potential failure
C5	A problem results in a long outage or major equipment damage
C6	An engineering safety feature actuation occurs during an event
C7	A particular occurrence is recognized as having a significant recurrence rate
C8	Other (explain)

4. OPERATING EXPERIENCE REVIEW OF SAN ONOFRE UNIT NO. 1

4.1 Summary of Operational Events of Safety Importance

This study reviewed the operational history of San Onofre Unit No. 1 to indicate those areas of plant performance that have compromised plant safety. The review included a detailed examination of plant shutdowns, power reductions, reportable events, and special environmental reports. The criteria used to show degradations in plant safety were

1. events that initiated a design basis event (DBE), and
2. events that compromise safety functions designed to mitigate the propagation of DBE initiating events.

Shutdowns and power reductions indicated the number and types of DBEs entered. Reportable events and special environmental reports indicated DBEs and the number of times each engineered safety function was lost. The results of the operational review identified 26 DBEs entered and 15 losses of safety function.

4.2 General Plant Description

San Onofre Nuclear Generating Station Unit No. 1 is a Westinghouse pressurized water reactor (PWR) with 436 MWe net maximum capacity. The owners are Southern California Edison, who serves as the operating agent, and San Diego Gas and Electric Company. The architect/engineer is Bechtel Corporation. The plant is subject to provisional operating license DPR-13, issued on March 27, 1967, pursuant to docket number 50-206.

San Onofre Unit No. 1 achieved initial reactor criticality on June 14, 1967 by means of boron dilution. The generator first synchronized to the grid on July 17, 1967. On January 1, 1968, commercial operation commenced at a maximum net power of 385 MWe. Full net power of 430 MWe was first achieved on December 27, 1968 and the plant was licensed for 450 MWe-gross on September 20, 1969.

Located near San Clemente in San Diego County, California, the plant lies entirely within Camp Pendleton Marine Reservation (Fig. 4.1). Thus the immediate surrounding area is sparsely populated. The nearest city of 50,000 or more people is Oceanside, California located seventeen miles southeast of the plant with a population of 80,000. Within thirty miles of the plant, there are four cities and a population of 410,000. Within fifty miles, there are twenty-nine cities and a population of 3,600,000. The plant is sixty-two miles southeast of Los Angeles and fifty-one miles northwest of San Diego.

4.3 Availability and Capacity Factors

Table 4.1 contains the availability and capacity factors for San Onofre Unit No. 1. San Onofre Unit No. 1 began commercial operation of

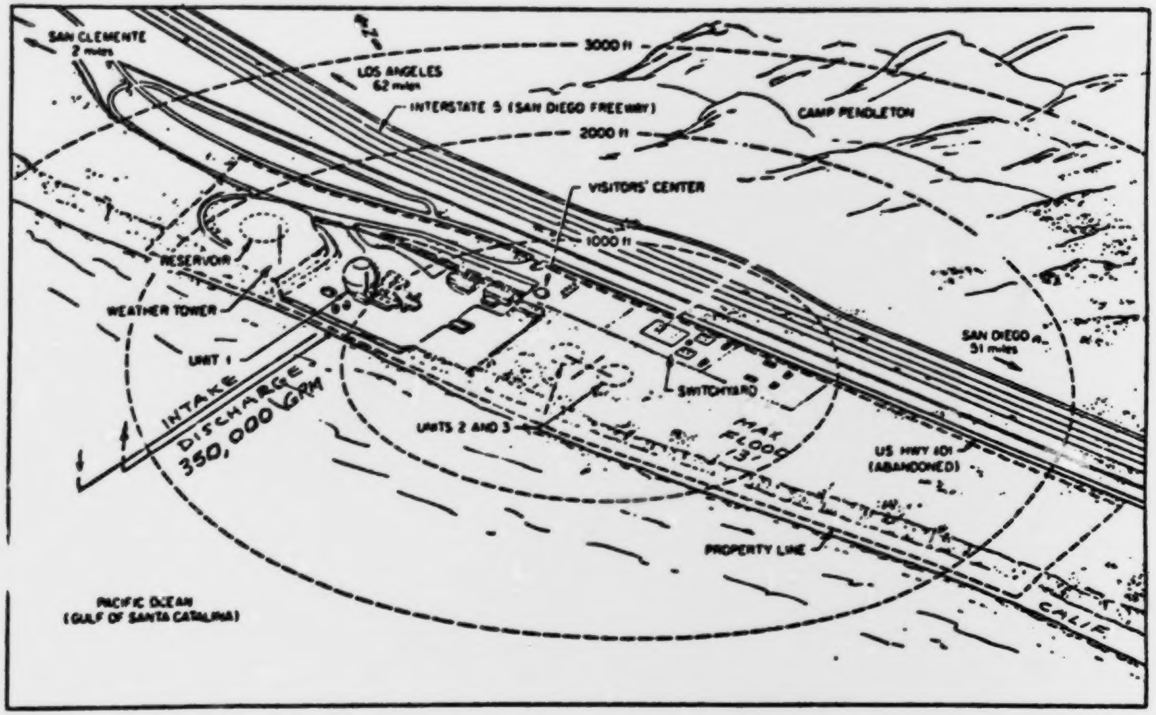
SAN CLEMENTE
2 miles
LOS ANGELES
62 miles
3000 ft
INTERSTATE 5 (SAN DIEGO FREEWAY)
CAMP PENDLETON
2000 ft
VISITORS' CENTER
1000 ft
RESERVOIR
WEATHER TOWER
UNIT 1
INTAKE
DISCHARGE
350,000 GPM
SWITCHYARD
SAN DIEGO
51 miles
UNITS 2 AND 3
MAX FLOOD 13'
US HWY 101
(ABANDONED)
PROPERTY LINE
PACIFIC OCEAN
(GULF OF SANTA CATALINA)
CALIF.

Figure 4.1 San Onofre Plant Site

Table 4.1. Availability and capacity factors for San Onofre 1

	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Reactor availability	62.5	42.3	76.7	83.7	94.5	79.3	63.7	86.9	87.9	72.2	64.3	81.7	90.4	22.6	28.0	68.3
Unit availability	36.4	41.5	75.8	83.0	93.4	77.8	62.8	86.1	87.4	70.2	63.7	80.2	90.2	22.3	26.7	68.0
Unit capacity (MDC) factor[a]	17.8[c]	34.4[c]	69.8[c]	81.3[c]	88.0[c]	75.2[c]	60.3	83.5	86.2	65.5	61.1	70.1	87.9	21.3	20.4	65.7
Unit capacity (DER) factor[b]	17.8[c]	34.4[c]	69.8[c]	81.3[c]	88.0[c]	75.2[c]	60.3	83.5	86.2	65.5	61.9	70.1	87.9	21.3	20.4	65.7

[a] MDC = maximum dependable capacity.

[b] DER = design electrical rating.

[c] Used (MWe) gross.

January 1, 1968. The reactor availability in the period 1968 through 1981 was above 70% except for five years: 1968, 1973, 1977, 1980 and 1981. In 1968, the reactor shut down for over six months due to cable tray fires which occurred on February 7 and March 12. The reactor shut down for approximately two and one-half months in 1973 to repair a turbine blade failure. In 1977, the reactor shut down for one month due to reactor coolant pump inspection, and steam generator tube inspection and plugging. Steam generator tube repairs caused the reactor to shut down for eleven months in 1980 and 1981 beginning in July, 1980. In the fourteen years of commercial operation, the reactor availability has averaged 68.3% while unit availability averaged 68.0%. Unit capacity (MDC) is the same as unit capacity (DER) for San Onofre Unit No. 1 and averaged 65.7%.

4.4 Forced Reactor Shutdowns and Forced Power Reductions

Tables A.1.1 through A.1.15 in Appendix A provide a comprehensive summary of forced shutdowns and forced power reductions at San Onofre Unit No. 1. Tables 4.2 and 4.3 summarize Tables A.1.1 through A.1.15 for forced shutdowns and forced power reductions, respectively. The duration of the event is rounded to the nearest hour for forced outages. All power reductions are defined as outages of zero hours duration for computing unit capacity and availability factors and forced outages rates.

4.4.1 Review of reactor shutdowns and power reductions

There were 107 forced shutdowns and 47 power reductions for the reporting period 1967 through 1981 with an average of seven forced outages per year. The average time the unit was shut down due to these occurrences was 1774 h/year. Two outages, one in 1968 (cable tray fire) and one in 1980 (steam generator repair), were responsible for 12507 h of downtime amounting to 47% of the total forced outage downtime experienced through 1981. If these two events were not considered, the average downtime due to forced shutdowns was 940 h/year. Approximately one-fourth of these occurrences were identified as DBE-initiating events as defined in Sect. 3.1.1.

4.4.1.1 Yearly summaries for San Onofre Unit No. 1

1967

On June 14, 1967, San Onofre Unit No. 1 achieved initial criticality by boron dilution. The generator was first synchronized to the grid on July 16. During turbine overspeed testing on July 17, salt water leakage into the condenser was noted. A turbine blade failure sent metal fragments into the condenser, causing salt water leakage. All of the blades in the last four stage rows required replacement. The outage lasted ~1080 h and accounted for almost 2/3 of the forced outage down time for 1967.

On September 11, the unit shut down for ~192 h due to excessive vibration in the circulating water pump and a leaking pressurizer safety

Table 4.2. Forced shutdown summary for San Onofre 1

	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
I. Forced shutdowns																
1. Total number	9	9	9	1	12	12	3	4	4	9	10	5	6	5	9	107
2. Total hours down	1668	5105	2122	2	426	661	2083	1130^{d}	143	178	761	495	857	4581	6396	26608
3. Cause^{a}																
a. Equipment failure	7 (1524)	7 (5056)	8 (925)^{c}	1 (2)	8 (156)	11 (499)	3 (2083)	3 (583)^{d}	2 (6)	6 (165)	6 (93)	2 (14)	4 (459)	2 (19)	8 (6390)^{e}	78 (17948)
b. Maintenance or testing			1 (1193)		4 (270)	1 (162)		1 (547)	1 (127)	1 (6)	3 (674)		2 (398)	1 (4152)	1 (6)	16 (7535)
c. Regulatory restriction												1 (472)		1 (372)		2 (844)
d. Administration																
e. Operational error	2 (144)	2 (49)								1 (20)	1 (4)	1 (5)				7 (222)
f. Other									1 (10)	1 (7)		1 (4)		1 (38)		4 (59)
II. Total number of DBE related shutdowns (these are included in totals of part I)	2 (12)	4 (179)	2 (130)		2 (18)	3 (63)	1 (1974)	1 (7)		3 (36)	3 (50)	2 (9)		1 (38)	2 (1484)	26 (4000)
III. System involved																
1. Reactivity control (RB)	3 (12)	4 (179)	1 (86)			1 (4)		2 (62)^{b}			3 (50)					14 (393)
2. Coolant recirculation systems and controls (CB)	2 (408)	5 (4926)	4 (614)		1 (180)^{b}			1 (5)	2 (131)^{b}	2 (12)	1 (646)^{b}	1 (10)		1 (11)	1 (38)	21 (6987)
3. Containment heat removal systems and controls (SB)											1 (27)					1 (27)
4. High-pressure safety injection systems and controls (SF-C)							1 (1974)^{b}				1 (25)		1 (234)		1 (1466)	4 (3699)
5. Offsite power systems and controls (EA)					1 (6)					1 (7)		1 (4)				3 (17)
6. AC onsite power systems and controls (EB)					2 (62)								1 (133)			3 (195)
7. Onsite power systems and controls (composite AC and DC) (ED)							1 (1)		1 (2)		2 (6)				1 (1466)	5 (1476)
8. Emergency generator system and controls (EE)															1 (740)	1 (740)
9. Chemical, volume control, and liquid poison systems and controls (PC)		1 (152)														1 (152)
10. Turbine-generators and controls (HA)	1 (1080)		4 (1257)^{b}	1 (2)	5 (49)	6 (221)	1 (1974)^{b}	1 (516)^{b}		4 (52)	1 (3)	1 (5)		1 (8)	1 (19)	27 (5186)
11. Main steam supply system and controls (HB)	1 (216)^{b}		1 (1193)^{b}			3 (344)	1 (108)	1 (547)	1 (127)^{b}	1 (101)	1 (646)^{b}	2 (476)^{b}	1 (394)	1 (4152)	2 (4030)^{e}	16 (12336)
12. Main condenser systems and controls (HC)					1 (17)	1 (162)^{b}	1 (1974)^{b}	1 (516)^{b}					1 (82)^{b}			5 (2751)
13. Circulating water systems and controls (HF)	2 (216)^{b}		1 (165)						1 (10)							4 (391)
14. Condensate and feedwater systems and controls (HH)					2 (284)^{b}	3 (254)^{b}				1 (6)		1 (4)	1 (82)^{b}	1 (38)	2 (28)	11 (696)
15. Reactor trip (IA)	2 (144)				1 (8)			1 (55)			1 (4)		1 (4)		1 (59)	7 (274)
16. Engineered safety feature instrument systems (IB)													1 (10)		1 (25)	2 (35)
17. Not applicable/unknown														1 (372)		1 (372)

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[a] Number of hours associated with cause of shutdown is in parentheses.

[b] Other systems involved. Maximum possible hours listed as breakdown in hours for each system unknown.

[c] Includes continuation outage of 160 h.

[d] Includes continuation outage of 516 h.

[e] Includes continuation outage of 4023 h.

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Table 4.3. Power Reduction Summary for San Onofre 1

	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
I. Power reductions																
1. Total number			4			1	2	3		12	3	7	10	2	3	47
2. Cause																
a. Equipment failure			4				2	3		6	1	3	2	1	2	24
b. Maintenance or testing										5	2	3	7	1	1	19
c. Regulatory restriction																0
d. Operator training/license exam																0
e. Administrative																
f. Operational error						1						1	1			3
g. Other										1						1
II. Total number of DBE related power reductions (included in totals of part I)							1									1
III. System involved																
1. Reactivity control (RB)			1			1	1			1		2				6
2. High-pressure safety injection system (SF-C)												1				1
3. Reactor trip (IA)								2								2
4. Offsite power systems and controls (EA)										1						1
5. Onsite systems and controls (composite AC and DC) (ED)			3			1	1			2						7
6. Turbine-Generators (HA)													1	1		2
7. Main condenser systems and controls (HC)										7	2	2	8	1	2	22
8. Circulating water systems and controls (HF)											1	1	1			3
9. Condensate and feedwater systems and controls (HH)								1		1		1			1	4

valve. The vibration was caused by pulling in an excessive amount of marine growth into the circulating water system.

The unit shut down on July 9 and December 12 because malfunctioning or defective electrical equipment was resulting in control rod drops. On October 19, a false indication of a fully inserted control rod from a bad connector in the position indication circuitry resulted in a unit shutdown. Dropped rods and false indications of dropped rods were recurring events in San Onofre Unit No. 1's early operating history. Section 4.4.3.4 discusses indication of dropped rods.

On December 5, the reactor tripped during a power increase due to an incorrectly set reactor overpower set point. The overpower protection was set at 85% power. During the power increase the protection was not reset and reactor trip resulted when power output reached 85%. The warning alarm failed to operate as the set point level was approached.

With one circulating water pump out of service, the unit was manually tripped when an inadvertent closure of the tsunami gate occurred on November 1, 1967. A shorted limit switch caused the closure.

1968

There were nine forced outages accounting for 5105 h of downtime in 1968. The first outage occurred on February 7 when a fire started in the cable tray containing the cables leading to sphere electrical penetration EPC-4. The cause of the fire was electrical and mechanical overloading of power cables for the pressurizer heaters. A month later, on March 12, another cable failure resulted in a fire. The cause of this cable failure was a higher than design thermal loading of circuits that supply the pressurizer heaters. These two events shut down the reactor for 4618 h and are discussed in more detail in Sect. 4.5.2.2.

In 1968 there were four events of dropped or bottomed control rods (March 4, March 9, September 9, and September 26 which shut down the reactor for a total of 180 h (see Sect. 4.4.2.6).

Beginning December 9, an increased temperature in valve discharge piping indicated leakage through a pressurizer relief valve. Observation continued until December 28 when the unit was shut down. It remained down for 244 h. Pressurizer relief valves are discussed in more detail in Sect. 4.4.3.1.

1969

In 1969, there were nine forced outages accounting for 2122 h of downtime. There was one major outage this year which commenced on June 20. The unit shut down for 1193 h to allow inspection of the turbine-generator and to make modifications to the steam generator moisture separators.

On March 22 and August 10, the unit shut down for a total of 394 h to replace leaking pressurizer relief valves. On October 9, the unit was removed from operation for 165 h when the tsunami gate slipped from its anchor bolts and fell into the intake tunnel.

On April 7, a load runback resulted from an unexplained false dropped rod signal. This false signal necessitated a power reduction to investigate the problem. On August 14, a relay malfunction caused several control rods to drop and the reactor was manually tripped. Failure of a recirculation valve motor winding caused the plant to remain shut down for 86 h.

1970

Only one forced outage interrupted operation in 1970. On May 29, a reactor trip occurred subsequent to a manual turbine trip. The turbine trip was due to an acceleration rate greater than desired. The reactor tripped because 2 of 4 power channels indicated greater than 10% power. The total forced outage downtime for the year was two h.

1971

The reactor availability factor of 94.5% for 1971 was the highest achieved during the time period covered by this review. There were twelve forced outages totaling 426 h downtime. This year was the first in which the unit shut down to repair leaking condenser tubes. The unit shut down on June 27 for 17 h and October 27 for 104 h for this cause.

On November 1, 3, and 5, the unit was shut down three times to obtain additional data on turbine overspeed characteristics (see Sect. 4.4.3.2).

1972

There were twelve forced outages totaling 661 h in 1972. The initial repair of leaking steam generator tubes occurred during this year. On July 8, a leak in "C" steam generator tube was detected. Sampling began and continued until the leakage was ~100 gal/d. On July 19, the unit shut down for 177 h to repair the leak. On September 12, analysis determined that the "A" steam generator was experiencing primary to secondary side leakage. Sampling began and continued until the leakage was over 100 gal/d. The unit was then shut down for 155 h on October 13 for repairs of the tube leaks.

On April 30, during startup, the reactor and turbine tripped due to a turbine trip caused by high steam generator water level. The high level resulted from failure of the positioner on the main feedwater regulating valve. This event is discussed in more detail in Sect. 4.4.2.1.

On February 25, March 4, and March 24, the unit shut down for a total of 23 h because of additional turbine overspeed problems and testing. Indication of dropped control rods continued to occur causing a unit shutdown on September 20 and power reduction on December 9.

1973

There were only three forced outages in 1973. However, total downtime was 2083 h. The major outage for the year started on October 21 and accounted for 1974 h downtime. Bearing vibration and salt water leakage indicated turbine problems existed. While shutting the unit down, a feedwater control error caused overcooling, resulting in safety injection actuation and a reactor trip. Section 4.4.2.1 describes this event in detail.

On January 6, the unit shut down for 108 h to locate and repair "A" steam generator tube leaks. For more information on this and subsequent steam generator tube leaks refer to Sect. 4.5.3.2. On January 10, the reactor tripped when No. 4 vital bus was transferred from the backup power supply to the normal power supply.

On February 20, an indication of a dropped rod occurred during a power reduction for condenser cleaning. On August 17, another power reduction was initiated when failure of an inverter caused a load transfer.

1974

In 1974, there were four forced outages totaling 614 h. The longest outage began on April 27 when the unit shut down for 547 h to repair steam generator and reheater tube leaks and to repair a leaking pressurizer safety valve.

On June 11 and June 14, the unit initiated a power reduction as a result of automatic load runbacks. Problems with inverters which supply power to nuclear power range monitors caused the runbacks. On October 21, the reactor was manually tripped during a load increase when control rods in subgroup 8 dropped.

1975

Of the four forced outages totaling 143 h, the longest outage of 1975 commenced on June 11. The unit shut down for 127 h to repair pressurizer relief valves and to plug leaking steam generator tubes.

On February 19, an inverter failed causing a spike in a pressurizer level channel. This forced the unit down for 4 h. On April 22, the reactor tripped while transferring the No. 4 vital bus back to its normal power supply.

1976

Nine forced outages totaled 178 h in 1976. On July 30, the unit shut down for 101 of the 178 h to repair leaking steam generator tubes in "C" steam generator.

On March 23 and March 29, the unit reduced power to investigate salt water in-leakage into the condenser. On five days (January 8, January 26, January 29, February 6, and July 2), the unit reduced power in order to plug leaking condenser tubes.

The unit scrammed on February 9 and reduced power on September 25 and 26 because of problems with inverters. The events on September 25 and 26 also caused erroneous indications of dropped control rods.

On April 17 through 19, there were four events involving turbine overspeed resulting from incorrect turbine trip settings. The unit was shut down a total of 42 h.

1977

During 1977, there were ten forced outages totaling 761 h. On September 9, the reactor shut down for reactor coolant pump inspection, steam generator inspection, and plugging of leaking tubes in the steam generators. On July 1 and 2, the unit reduced power in order to plug leaking tubes in the south half of "B" condenser.

On April 14 there was an erroneous indication of a dropped rod and actual dropped rod events occurred on May 18 and June 9. The unit shut down a total of 50 h during these events.

1978

There were five forced outages totaling 495 h of downtime in 1978. On April 5, the unit shut down for 472 h (95% of the year's forced downtime) in order to inspect the steam generators. This shutdown was required by NRC.

On March 29 and June 9, the unit reduced power in order to plug leaking condenser tubes. On March 22 and May 18, the unit reduced power due to erroneous dropped rods indications.

1979

The 1979 reactor availability factor was 90.4%. This was the second highest in the operating history of San Onofre Unit No. 1. There were six forced outages totaling 857 h. On April 5, the unit shut down for 82 h to repair a condenser tube leak and to repair the feedwater flow straighteners. In addition, there were seven other occasions (February 23, August 30, September 7, November 29, twice on November 30, and December 12) involving condenser tube leaks which necessitated the unit to reduce power to repair or plug the leaking tubes.

On June 1, the unit went down for 394 h to plug leaking steam generator tubes. On September 14, the unit shut down for 234 h in order to repair refueling water pump suction piping and to replace several pipe sections on the safety injection line. On November 7, the unit shut down for 133 h due to loss of 480 V bus No. 1 (see Sect. 4.5.3.1).

1980

The 1980 reactor availability factor was 22.6%. This was the lowest reactor availability reported for San Onofre Unit No. 1 in the time interval of this review. Although there were only five forced outages, the five accounted for 4581 h of downtime. After completing refueling on July 12, the unit remained shut down for 4152 h to complete steam generator tube repair.

On January 26, the unit shut down for 392 h in order to effect TMI modifications. On February 17, the unit reduced power to repair a salt water leak into the condenser.

On January 16, the unit shut down for 38 h due to a steam flow/feedwater flow mismatch caused by a construction worker who accidently struck the closing circuit control relay to the east feedwater pump.

1981

In 1981 San Onofre Unit No. 1 continued the shutdown to repair steam generator tubes for an additional 4023 h. This was the primary contributor to the reported reactor availability of 28%. The reactor returned to operation on June 17, 1981, and experienced nine forced shutdowns and three power reductions in the remainder of the year.

4.4.1.2 Systems involved. There were seventeen systems involved in the 154 forced outages and power reductions (Tables 4.2 and 4.3). For several of these events, more than one system was involved in the event. In these cases, the outage time was charged to each system involved. Four systems which each were involved in twenty or more events were:

(1) Turbine-Generators and Controls — Twenty-nine events involving the turbine generator and controls system totaled 5186 h. Two outages (July 17, 1967, October 21, 1973) dealing with turbine blade failures and one dealing with modifications of moisture separators (June 20, 1969) accounted for the majority (82%) of the outage time for this system.
(2) Main Condenser and Controls — Twenty-seven events involved the main condenser and controls totaling 2751 h of downtime. Most of these events were power reductions for the purpose of repairing minor condenser tube leaks. The outages of July 17, 1967 and October 21, 1973, resulted from turbine blade damage causing salt water inleakage to the condenser.
(3) Reactivity Control — The reactivity control system accounted for twenty events and 393 h of downtime. Almost all of these events dealt with dropped rods or indications of dropped rods. This was a recurring problem in the early operating history of San Onofre Unit No. 1, but has not reoccurred since May 1978.
(4) Coolant Recirculation — Twenty-one events totaled 6987 h of downtime because of failures involving the coolant recirculation system and controls. The two events (February 7, 1968, March 12, 1968) in 1968, dealing with the cable tray fires, accounted for 70% of the outage time.

Two other systems were involved with a significant number of forced shutdowns:

(1) Main Steam Supply — sixteen times totaling 12334 h, and
(2) Condensate and Feedwater — ten times totaling 696 h.

The additional eleven systems each were involved in forced shutdowns fewer than nine times and averaged less than three shutdowns per system. Eight of these eleven systems had less than 400 h charged to them with an average of 183 h. The remaining three systems were:

(1) High pressure safety injection — four events for 3699 h,
(2) Onsite power systems and controls — five events for 1476 h, and
(3) Emergency generators and controls — one event for 740 h.

4.4.1.3 Causes of forced reactor shutdowns and forced power reductions. Equipment failure accounted for seventy-eight outages and twenty-four power reductions (Tables 4.2 and 4.3). The total forced outage downtime through 1981 due to equipment failure was 17,948 h. Steam generator problems, leaking pressurizer relief valves, turbine blade failures, dropped control rods, failure of inverters, and turbine overspeed problems accounted for most of the equipment failures.

Maintenance and testing accounted for sixteen outages (7535 h) and nineteen power reductions. Modifications to the moisture separators, inspections, condenser tube leaks, and steam generator tube leaks accounted for most of these events.

The unit shut down twice due to regulatory required inspections of the steam generators and for TMI modifications. During 1978 the unit reduced power for extended periods due to an administrative decision to defer fuel depletion.

There were only seven events related to operational error totaling 222 h. There were primarily two areas involved. The first dealt with incorrect settings for turbine overspeed while the second dealt with false indications of dropped rods due to introduction of spurious signals. The only event of major importance was the unexpected opening of a feedwater pump safety injection valve during maintenance which occurred on August 18, 1978. Opening the valve resulted in dilution of the refueling water storage tank (RWST). The unit reduced load and added boric acid to the RWST to compensate for the dilution.

There were five events related to other causes. Two of these were due to brush fires around San Clemente. One resulted in a loss of one train of offsite power on January 21, 1976 and the second required a precautionary power reduction on the following day. The event of January 16, 1980, involved steam flow/feedwater flow mismatch resulting from an inadvertent action of a construction worker. On May 21, 1975, the reactor was manually tripped due to seaweed blocking flow into the intake structure. An offsite power disturbance that resulted in a scram on March 8, 1978, due to low voltage is discussed in Section 4.4.2.5.

4.4.1.4 Non-design basis events. There were 127 non-DBEs of which eighty-one were forced shutdowns and forty-six were power reductions (Table 4.4). These events can be classified into the following categories:

(1) pressurizer relief valves (seven events),
(2) steam generator tube leaks (nine events),
(3) leaks in the condenser (twenty-five events),
(4) turbine overspeed protection (fourteen events),
(5) power buses and inverters (twenty-six events), and
(6) others.

The first five categories deal with recurring events and are discussed in Sect. 4.4.3 or Sect. 4.5.3.

4.4.2 Review of design basis events

There were twenty-seven design basis events (DBEs) accounting for 18% of the total number of events and resulting in twenty-six forced outages

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Table 4.4. NSIC primary category summary for non-DBE shutdowns and power reductions for San Onofre 1

	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
1. Equipment failures	2	3	8	2	2	4	1	2	1	7	5	4	5	3	7	56
2. Instrumentation and control anomalies	2		1		1	1		2		1		2			2	12
3. Non-DBE reductions in coolant inventory (leaks)	2	2	2		4	3	1	2	1	8	4	2	10	1		42
4. Fuel/cladding failure																0
5. Maintenance error																0
6. Operator error	1					1	1		1		1	1	1	1		8
7. Procedural/administrative error					3										1	4
8. Regulatory restriction												1		1		2
9. External events									1	2						3
10. Environmental operating constraint-tech. specs.																0
TOTAL	7	5	11	2	10	9	3	6	4	18	10	10	16	6	10	127

(Table 4.5). The total downtime associated with the outages was 4000 h. Six DBE category types occurred with four categories having more than one event.

4.4.2.1 D1.2 Feedwater system malfunctions that result in an increase in feedwater flow. Four events occurred that are considered design-basis D1.2 events. On April 30, 1972, the unit had just completed a normal reactor startup and was operating on line at 55 MWe with load being slowly increased. The auxiliary feedwater regulators were in service and controlling steam generator water levels. As the feedwater block valve to "C" steam generator was opened, flow increased rapidly causing the turbine and reactor to trip from high level in "C" steam generator. The high level resulted from failure of the positioner on the main feedwater regulating valve. The primary coolant temperature experienced a temperature drop of 91°F. Safety injection equipment was actuated ~12 min after the reactor trip. As a result, feedwater flow to the steam generators ceased and the cooldown in the primary system terminated.

Nine minutes after actuation, the safety injection system was secured. The operation of the safety injection system was normal. However, since the minimum reactor coolant system pressure was significantly above the main feed pump shut-off head, no borated refueling water was delivered to the reactor coolant system through the normal safety injection flow path. Approximately 900 gallons of borated water were delivered to the coolant system through the normal charging path. An analysis to evaluate the thermal effects of this incident concluded that the reactor coolant system did not undergo any damage due to the thermal transient and the unit could be safely returned to operation.[14,15]

The second feedwater system malfunction that resulted in an increase in feedwater flow occurred on October 21, 1973. The unit was being removed from service to investigate turbine problems indicated by bearing vibration and salt water leakage. During the unit shutdown, rapid cooldown of the primary cooling system resulted in the initiation of the safety injection system and a reactor trip.

Blowdown on all three steam generators was commenced at 12:15 a.m. and a unit load decrease was initiated. At 1:18 a.m., the turbine was in an unloaded status and a no load trip alarm was received. At 1:19 a.m. the turbine stop valves closed, and since feedwater control was still on automatic, the feedwater regulator valves went to 80% open. As a result reactor coolant temperature and pressure began decreasing rapidly.

The operator changed reactor and feedwater control to manual in an attempt to increase temperature. Steam generator levels were increasing rapidly and pressurizer level had decreased to 10%. At 1:21 a.m., the safety injection system initiated and the reactor tripped. Approximately 1300 gal of borated water from the refueling water storage tank entered the primary system through the charging pumps.

Safety injection had functioned as required. However, in restoring the system to standby, the Loop B safety injection valve was partially inoperable. The valve mounting bolts and a nearby pipe hanger had failed. Further investigation indicated the damage to the Loop B piping was due to water hammer.

The cause of the overcooling event was assessed as failure to place feedwater control in manual prior to removing the turbine from service.

Table 4.5. DBE initiating events at San Onofre 1

	DBE category	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
1. Feedwater system malfunctions that result in an increase in feedwater flow	D1.2						1	1								2	4
2. Loss of external electric load	D2.2					2	2										4
3. Turbine trip	D2.3			1							3		1				5
4. Loss of normal feedwater flow	D2.7														1		1
5. Single and multiple reactor coolant pump trips	D3.1												1				1
6. Control rod maloperation	D4.3	2	4	1				1	1			3					12
Total		2	4	2	0	2	3	2	1	0	3	3	2	0	1	2	27

Additionally, changes in steam generator control upon turbine trip were considered.[16,17]

The last two DBE D1.2 events occurred in 1981. The first resulted in a scram and seven hour shutdown on June 18, 1981. An instrumentation and control malfunction resulted in a steam and feed flow mismatch, causing the reactor trip. On September 3, 1981, a voltage regulator failure initiated an overcooling event requiring a manual scram. The recovery from the failure resulted in a significant reportable event and is described in Section 4.5.2.1.

4.4.2.2 D2.2 Loss of external electric load. There were four events associated with the category — loss of external electric load. The first loss of load event occurred on June 22, 1971. Both the Chino and Santiago lines relayed and the generator tripped on overspeed. On July 12, 1971 the unit tripped from a generator out-of-step condition again resulting in turbine overspeed. In the third event, the main exciter motor failed mechanically when being started on July 27, 1972. The problem was determined to be rubbing between the rotor and stator. On July 29, 1972, the unit tripped from loss of main generator field and experienced a turbine overspeed. The turbine overspeed events are described in Section 4.4.3.2.

4.4.2.3 D2.3 Turbine trip. There were five events associated with the category — turbine trip. On January 9, 1969, the unit was removed off line after a routine test of the stop valves produced a spurious partial turbine trip. Investigation revealed that the turbine auto stop oil supply pressure was low due to a badly scored seat and disc in the autostop oil dump valve. During startup, twice on April 17, 1976 and once on April 18, 1976, a spurious turbine trip resulted in a reactor trip. The cause was an incorrect setting of an overspeed trip device. On September 12, 1978, the turbine and reactor tripped while performing bearing low oil pressure tests.

4.4.2.4 D2.7 Loss of normal feedwater flow. On January 16, 1980, the unit tripped from steam flow/feedwater flow mismatch. The trip was caused by a construction worker who accidently struck the closing circuit control relay to the east feedwater pump normal discharge valve. This resulted in a rapid decrease in feedwater flow and the resultant trip.[18]

4.4.2.5 D3.1 Single and multiple reactor coolant pump trips. On March 8, 1978, the reactor tripped from a loss of coolant flow signal. The low flow condition occurred when a severe voltage reduction at the reactor coolant pump motors resulted from a power system disturbance. This reduced pump speed such that a low flow condition existed. The disturbance was due to a fault occurring on the San Diego Gas and Electric Company power grid which interties to San Onofre.

4.4.2.6 D4.3 Control rod maloperation. There were eleven forced outages due to dropped rods. The problems with dropped rods were of four types:

(1) relay malfunctions (3),
(2) slave cycler malfunctions (2),
(3) gripper coil malfunctions (3), and
(4) connector malfunctions (1).

On two additional occasions, October 21, 1974 and April 14, 1977, rods dropped for unknown reasons.

On July 9, 1967, a timer relay malfunctioned which caused rod drops in subgroup 4 of control rod group No. 1. On September 9, 1968, all five rods on subgroup 7 slipped from 117 to 40 steps due to BF relay failures. On August 14, 1969, control rods associated with subgroup 7 dropped into the core due to an intermittently open contact of a BF type relay in the rod control logic.

On March 4, 1968, cleaning of the rod controls slave cycler contacts was in progress and the subgroup No. 6 slave cycler had been replaced with a shutdown cycler so that the contacts could be cleaned. An attempt was made to cycle the rods one step and subgroup No. 6 was dropped to 160 steps. The slave cycler was examined and no reason for failure was found. On September 26, 1968, the control rods on subgroup 8 dropped into the core while a slave cycler failure alarm was being cleaned. This occurred when an operator manually opened, closed, and reopened the half-power contactor while attempting to clean a slave cycler failure alarm. The cause was due to improper operation of the slave cycler clutch.

On March 9, 1968, the unit was shut down when physics data indicated a bottomed control rod. Investigation revealed that the polarity of the movable gripper coil had been reversed during repairs to penetration EPC-4. On May 18 and June 9, 1977, a gripper coil failed causing four rods to drop which caused the unit to be manually tripped.

On December 12, 1967, five control rods in subgroup 7 dropped because of bad connectors in the vessel head. The defective electrical components were replaced.

4.4.3 Trends and safety implications of forced reactor shutdowns and forced power reductions

There were five major trends associated with forced outages and power reductions. These trends can be classified into one of the following categories of problems concerning:

(1) pressurizer relief valves,
(2) turbine overspeed,
(3) leaks in the condenser,
(4) indications of dropped rods,
(5) power buses and inverters, and
(6) steam generator tubes.

The pressurizer relief valves and the turbine overspeed problems mainly occurred during early years of operation. Leaks in the condenser occurred throughout San Onofre's operating history with most of these resulting in forced power reductions. Problems with power buses and inverters occurred after the first five years of operation. As well, problems pertaining to steam generator tubes surfaced following the first five years of operation. Problems with power buses and inverters and steam generator tubes are discussed in Sects. 4.5.3.1 and 4.5.3.2, respectively.

4.4.3.1 Pressurizer relief valves. Problems with the pressurizer relief valves occurred primarily during the first three years of operation. On October 1, 1967, the unit shut down for 216 h to repair two

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pressurizer power relief valves and a bypass valve in a steam line. On December 9, 1968, leakage through pressurizer relief valve RV-533 was observed by an increase in temperature in valve discharge piping. Observation continued until a normal shutdown was required on December 28, 1968, lasting 84 h. On March 22, 1969, leakage through pressurizer relief valve RV-533 was observed and the unit was shut down to repair the valve. Other scheduled work was accomplished at the time which caused the reactor to remain offline for 314 h. On August 10, 1969, the unit shut down for 80 h to correct leakage of three pressurizer relief valves. On April 27, 1974, during a shutdown to repair steam generators, repair of a pressurizer relief valve was also accomplished. On June 11, 1975, the unit shut down to repair safety valves RV-532 and RV-533.

4.4.3.2 Turbine overspeed. There were fourteen shutdowns caused by turbine overspeed or overspeed protection problems. On June 22, 1971, a fault on the San Onofre-Chino 220 kV line and a concurrent opening of the San Onofre-Santiago 220 kV line breakers caused a partial unloading of the unit. Downward drift in the backup overspeed device set point resulted in a complete electrical unloading of the units at a frequency of 61 Hz. Instrumentation indicated that the turbine-generator reached a maximum of 133% of normal speed. Three weeks later on July 12, 1971, the unit shut down due to a generator "out-of-step" condition caused by low generator excitation. This resulted in a complete electrical unloading of the unit. Instrumentation indicated that the turbine-generator reached a maximum of 133% of normal speed.

As a result of these two incidents, unit load was restricted to 80% of full power pending an evaluation of turbine overspeed characteristics. The results of this evaluation indicated that the unit load could be increased to full power provided (1) that condenser backpressure is a minimum of 1.5 in. of mercury absolute and (2) that the emergency overspeed trip was set at 104%. Load was increased to full power on August 9, 1971. On July 29, 1972, the unit tripped due to loss of the main generator field, during transfer to the main exciter. The unit had been operating with a spare, portable exciter. During the event the turbine reached 133% overspeed.

Six additional shutdowns (November 1, November 3, and November 5, 1971; February 25, and March 4, 1972; and March 19, 1976) were done to test the overspeed setting and gave data on overspeed characteristics.

Four events (March 24, 1972, April 17, 1976, April 17, 1976, April 18, 1976) resulted from incorrect settings of the overspeed trip and required resetting of the mechanical overspeed device. On May 29, 1970, the turbine was observed to be accelerating too fast and the unit was manually shut down.

4.4.3.3 Condenser tube leakage. Leaking condenser tubes caused five shutdowns and nineteen power reductions at San Onofre. The first time leaking condenser tubes became a problem was on July 17, 1967. The recurrence frequency did not increase until 1976, but continued to be high through 1979, decreasing in 1980.

Five shutdowns specifically to repair condenser tube leaks interrupted operation on July 17, 1967; June 27 and October 27, 1971; October 21, 1973; and April 5, 1979. On two occasions, July 17, 1967 and October 21, 1973, turbine blade failures caused salt water inleakage and resulted in 1080 and 2490 h of downtime, respectively.

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The first power reduction because of condenser tube leaks did not occur until 1976. However, as Fig. 4.2 indicates, condenser leaks caused recurring power reductions through 1981. Power reductions to repair condenser tubes occurred on January 8, January 26, January 29, February 6, March 23, March 29, and July 2, 1976; July 1 and July 2, 1977; March 2, and June 9, 1978; February 23, August 30, September 7, November 29, November 30, and December 2, 1979; February 17, 1980 and August 20, 1981.

4.4.3.4 Indications of dropped control rods. There were 14 events which resulted from indications of dropped control rods. Most of these were power reductions. Seven of these events (December 9, 1972, June 11 and June 14, 1974, February 9 and February 17, 1976; and September 25 and September 26, 1976) were associated with problems related to power buses and inverters and are discussed in Sect. 4.5.3.1. Two of the events (September 20, 1972 and February 20, 1973) are discussed in Sect. 4.4.2.6.

On October 19, 1967, the unit was shut down due to a false indication of dropped control rods. On April 7, 1969, the unit reduced power due to an unexplained false dropped rod signal. On March 22, 1978, an erroneous signal indicated dropped control rods.

On August 7, 1976, the unit reduced power due to a relay coil failure producing an erroneous dropped rod signal. On May 18, 1978, a grounded rod position indication system component caused an erroneous dropped rod signal.

4.5 Reportable Events

This study reviewed 327 reportable events from San Onofre Unit No. 1. The events included miscellaneous reports, abnormal occurrences (AO), station incidents (SI), and licensee event reports (LER) filed by the utility for various equipment failures or technical specification violations. The information in the reportable events was coded as discussed in Sect. 1.3. The tables compiling this coded information are in Appendix A, Part 2.

4.5.1 Review of reportable events from 1967 through 1981

Figure 4.3 illustrates the number of reportable events per year submitted by the Southern California Edison Company. The number of reported events remained relatively constant over the first half of San Onofre's Operating history. The second half tended to have increasing numbers. The years 1967 through 1974 average 17 events per year while the years 1975 through 1981 averaged 27 events per year. Reports of steam generator and condenser tube leakage were major contributors to the trend of increased numbers of reportable events. Peak reporting years were in 1980 and 1981 with 39 and 33 events, respectively.

4.5.1.1 Yearly summaries. The following sections present a summary of reportable events for each year of operation for San Onofre from 1967 through 1981. A single event which occurred in 1966 was also included in this study even though it occurred prior to initial criticality. During installation, a steam generator was dropped one foot during a lift. The steam generator withstood the subsequent hydraulic test, but 32 inconel

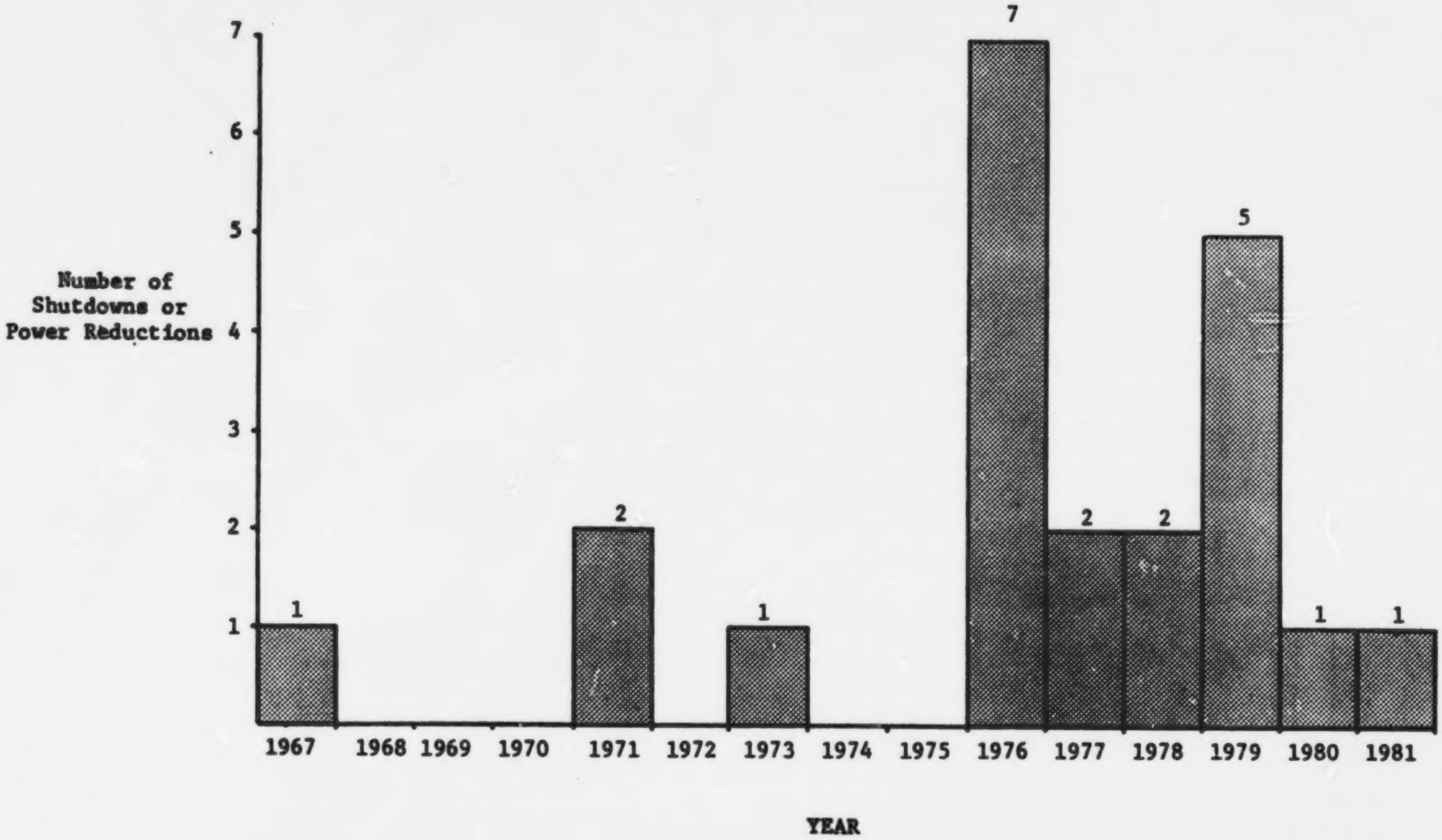

Figure 4.2 Number of Condenser Tube Leakage Events

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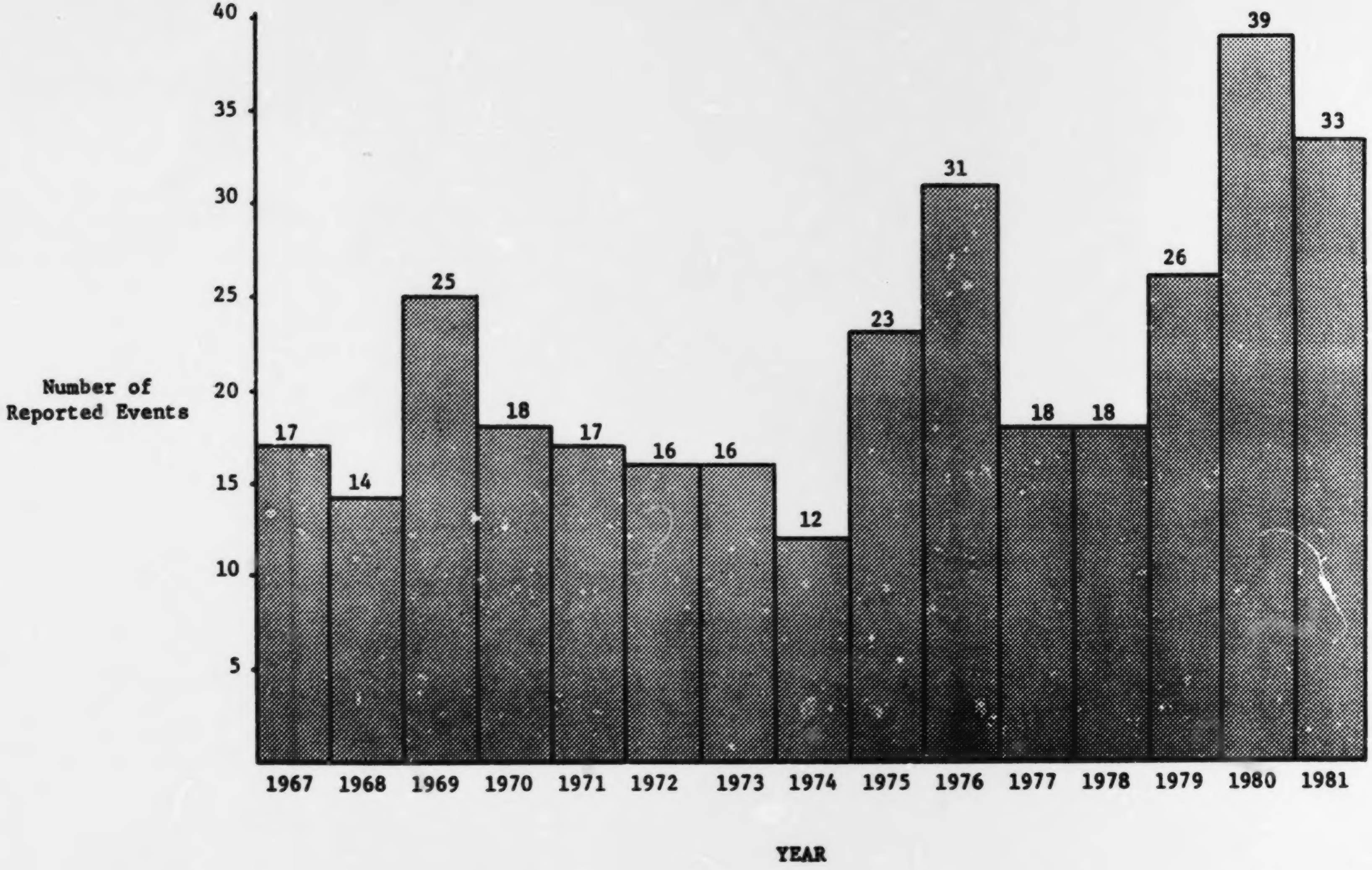

Figure 4.3 Number of Reported Events Per Year at San Onofre 1

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tubes were deformed and several tube support sheets were crushed. After making repairs and plugging tubes, the steam generator was placed in service.

1967

San Onofre Unit No. 1's initial criticality occurred in June 1967. This analysis examined 17 events that were reported during 1967. Two of those events are considered significant, one involving failure of both safety injection pumps and the secord a spill of radioactive water from the radwaste system. The first significant event occurred two weeks prior to initial criticality. Both safety injection pumps were declared inoperable when they failed megger tests. This common cause failure is discussed in Sect. 4.5.2.1. The second event involved the overflow of a radwaste tank due to operator error and is described in Sect. 4.5.1.4.

Of the remaining 15 events for 1967, 5 involved control rods or control rod drive mechanisms. These included two instances of inadvertent rod drops, two false or erratic rod position indications and one rod that mechanically jammed.

1968

Fourteen reportable events were reviewed for San Onofre for 1968. Two cable tray fires occurred, the second of which resulted in a five month shutdown. These signifiant events are discussed in Sect. 4.5.2.2. Also significant during the year was an event in which crystallization of boron in the lines required boration by an alternate means.

The remaining 11 events were not significant individually. Seven of them however, involved control rods. Five of these events were occasions when rods inadvertently dropped partially or completely into the reactor core. Two control rod anomalies were wiring faults.

1969

Twenty-five reportable events were recorded for 1969. Fourteen of these were termed "abnormal occurrences (AO)." This terminology was used prior to the current "licensee event report (LER)" and does not correspond to the current use of AO's as significant events that are reported to Congress by the NRC. One of the 25 events was identified as significant in this analysis. It involved another instance of boron crystallization inhibiting adequate boration (Sect. 4.5.2.6). The remainder of the events were insignificant and involved a variety of plant systems.

1970

In 1970, San Onofre reported 17 abnormal occurrences. In addition to those events, this review also included a reactor coolant pump event in which the pump flywheel was replaced when inspection revealed a cracked bore. None of the events examined were deemed significant. Five of the events were false control rod position indications, due to recurring LVDT failures. Three events involved safety injection system pumps or valves.

1971

Seventeen abnormal occurrences at San Onofre were reported in 1971. From these, this review identified two significant events, both involving occurrences of overspeed by the plant turbine. These occurrences required investigation and turbine modification and are described in Sect. 4.4.3.2. Of the remaining 15 events, 4 involved the reactor trip system, 2 resulting in inadvertent reactor scrams due to fabrication and maintenance errors.

1972

San Onofre reported 16 events in 1972. Two significant events occurred. Abnormal occurrence 72-07 reported an overcooling event due to an excessive feedwater flow rate. This was caused by a regulating valve failure and is described in Sect. 4.4.2.1. The second significant event was a recurrence of overspeed problems with the turbine, experienced subsequent to a loss of generator field.

Of the remaining 14 events, three events describe primary to secondary leakage in the steam generator. These are the first instances of steam generator tube leakage reported for San Onofre.

1973

In 1973, reportable events at San Onofre were reported as station incidents (SI). Sixteen such events were reported for the year. Two of those events were considered significant. SI 73-08 was a significant event involving loss of off-site power and subsequent failure of an emergency diesel generator. This event is described in Sect. 4.5.2.3. The second significant event was another overcooling event due to excessive feedwater flow. The transient resulted in actuation of the safety injection system. This event is described in more detail in Sect. 4.4.2.1.

In addition to the diesel generator failure in SI 73-08, four other diesel generator failures were reported during the year (SI 73-03, SI 73-04, SI 73-7, and SI 73-12). Prior to 1973 only two diesel generator failures had been reported, both in 1972.

1974

Twelve station incidents were reported by San Onofre for 1974. Of these twelve reported events, only one was deemed significant. SI 74-06 involved leakage of cooling coils in containment, causing flooding and failure of a number of reactor vessel detector thimbles. This resulted in a reactor trip and is discussed in Sect. 4.5.2.7.

One of the other events reported in 1974 was a sabotage threat against San Onofre which the FBI reported. The FBI received a telephone call from a Los Angeles man who claimed that a car with several persons was in route to San Onofre to "blow up" the generating station. The threat later proved to be a hoax.

1975

San Onofre reported 24 events in 1975, three of which were significant events. During a design review required by the NRC, a single valve failure was identified that could have potentially defeat the safety injection system. This discovery was reported as SI 75-06 and is discussed in Sect. 4.5.2.1. On consecutive days in August, the plant reported failure during testing of two different diesel generators due to inadequate cooling causing high cooling water temperature. These events are described in Sect. 4.5.2.4. Two other diesel generator failures (SI 75-02 and SI 75-04) were also among the rest of the 24 events for 1975.

1976

Eleven events were reported to the NRC as Licensee Event Reports (LERs) in 1976. The review also examined station incidents (SI) that San Onofre continued to record in its annual operating report. Table A2.11 shows only those SIs that describe events in addition to the LER events.

Twenty non-LER events were included in the review of 1976 operating experience, including 17 station incidents. Of these, one was deemed significant. It was a loss of off-site power event caused by a brush fire. The event (SI 76-02) is described in Sect. 4.5.2.3.

The 31 total events for 1976 included five reports describing failure of an inverter in the on-site power system. Three of these failures occurred on the same day and are discussed in Sect. 4.5.2.1. An additional five reports involved minor problems with spent fuel shipping casks. These included cracked lifting lugs, minor leaks and administrative errors in handling and shipping.

1977

Eighteen events were included in the review of 1977 operating experience. Fourteen of the eighteen were LERs. None of the events were considered significant. The problems presented by the reports were varied, including continued steam generator tube leakage, administrative errors and maintenance and design deficiencies.

1978

In 1978, 17 events were reported. Of the 17, one LER described a significant event. The event involved failure of two inverters for the containment spray actuation system.

Four of the remaining 16 events reported occurrences involving the high pressure safety injection system, while an additional three events involved feedwater system equipment. Although these events were reported as feedwater system events, some feedwater equipment is used in a safety injection role. None of the events were considered significant however.

1979

San Onofre submitted 26 LERs in 1979. Review of these reports identified no significant events. Five of the LERs involved events concerning

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loss of or failure to collect required environmental data such as drinking water samples and sea temperatures. These included loss of four environmental radiation dosimeters due to vandalism. In November, four LERs reported the discovery of pipe supports missing in three different systems

1980

In 1980, San Onofre Unit No. 1 submitted 39 Licensee Event Reports, the largest number of reports in any year. Four of those events were considered significant. The first of these was a cooling transient due to loss of a feedwater pump. The event was due to construction personnel in the area and is described in Sect. 4.4.2.4.

A second significant event occurred in March 1980 when all the salt water cooling flow for the plant ceased. The event was the result of pumps and valve failures, due to a number of causes and is described in Sect. 4.5.2.2. During refueling in April 1980, the third significant event occurred. Due to a seal failure, source range nuclear instrumentation was flooded and failed. This event is described in Sect. 4.5.2.7.

The final significant event of 1980 occurred in November and involved loss of on-site AC power to all station auxiliary loads. The event was caused by an operator error and is described in Sect. 4.5.2.3.

1981

San Onofre Unit No. 1 reported 30 events in 1981. Also three events reported as LERs in 1982 actually occurred in 1981. Of these 33 events, one event is considered significant. It involved failure to open of two safety injection valves, thereby disabling both trains of safety injection. The event which occurred on September 3, 1981, was due to a design error and is discussed in Section 4.5.2.1.

4.5.1.2 Systems involved in reportable events. A summary involved in reportable events is given in Table 4.6. The table totals the system codes listed in the "system" category of Appendix A.2 and gives the number of times a reported event involved each system by year.

The most frequently reported systems were:

1. coolant recirculation systems (29),
2. reactivity control systems (29),
3. condensate and feedwater systems (23),
4. onsite power systems (composite ac and dc) (19),
5. emergency generator systems (22), and
6. circulating water systems (18).

Eighteen of the 29 coolant recirculation system failures were damage to or leaks in the steam generators. The only other major contributors from this system were the reactor coolant pumps which accounted for six of the reports.

The majority (18 of 29) of reports involving the reactivity control system involved false indications of dropped rods. Ten reports concerned actual incidents of dropped rods and stuck control rod drives. The final

Table 4.6. Summary of systems involved in reportable events at San Onofre 1

System	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Reactor vessel internals (RA)											1						1
Reactivity control (RB)		5	7	5	5	2	1	1	1	1						1	29
Reactor core (RC)							1										1
Reactor vessel (CA)		1		2								1					4
Coolant recirculation (CB)	1	2	1		1	1	3	1	1	2	4	3		3	6		29
Residual heat removal (CF)															1	1	2
Reactor containment (SA)		1										2			1	2	6
Containment isolation (SB)				1			1	1		1				3	1	2	10
Low pressure safety injection (SF-B)		1	1	2						1						3	8
High pressure safety injection (SF-C)					3			1				1	4	1	3	4	17
Control room habitability (SG)															1		1
Containment spray (SH-B)												2	3	1		2	8
Auxiliary feedwater (SH-C)						1								1			2
Reactor trip (IA)				2	1	4	1		3	2				2		2	17
Engineered safety feature instrument (IB)											1				1	1	3
Safety related display instrumentation (ID)											2				1		3
Other instruments, safety (IE)															4		4
Other instruments, non-safety (IF)										1	2	2		1			6
Offsite power (EA)						1		2	1	1					1		6
AC onsite power (EB)			2								1			1	1	1	6
DC onsite power (EC)														2			2
Onsite power (composite AC and DC) (ED)				3		1	1	2	1	3	6	1	1				19
Emergency generator (EE)							2	5	1	4	1	1	2	1	2	3	22
Spent-fuel storage (FB)											5	2					7
Fuel handling (FD)										1					1		2
Station service water (WA)															1		1
Cooling for reactor auxiliaries (WB)									1			1		2	1	1	6
Compressed air (PA)															2		2
Chemical, volume control and liquid poison (PC)			1	2	2		1		1	1	1	1			1	1	12
Air conditioning, heating, cooling and ventilation (AA)		1		1													2
Turbine generators (HA)		1		1	1	4	3				1					1	12
Main steam supply (HB)		1			2	1			1		1			2	3		11
Circulating water (HF)		2	3	2						3			2	1	5		18
Condensate and feedwater (HH)				2	1		2	1	1	1	2		4	3	5	1	23
Liquid radioactive waste management (MA)		2												1			3
Process and effluent radiological monitoring (MC)													3				3
Area monitoring (RA)										1						1	2
Airborne radioactivity monitoring (RB)				1						2		1		3	1	1	9
System code not applicable (ZZ)				1	2	3		4	1		2						13
Total	1	17	15	25	18	18	16	18	12	25	31	18	19	28	43	33	

event occurred due to a weld failure causing one or two rodlets to remain in the core.

All 19 of the composite ac and dc onsite power system events were inverter failures. The events for the remaining three systems were not attributable to any single type or class of failures.

4.5.1.3 Causes of reportable events. Table 4.7 lists the causes of reportable events by year. The largest group of events (196) were those caused by inherent equipment failure. Human errors accounted for 113 events. These errors included administrative, design, fabrication, installation, maintenance, and operator errors.

Four events resulted from severe weather conditions. This included two losses of environmental data and two cases of excess fish and seaweed impingement at the intake. Three other reports of excess aquatic material at the intake were reported but were not attributed to weather conditions, so are listed as due to other, unspecified causes. This category also includes the eleven earthquakes reported by San Onofre Unit No. 1, one brush fire that caused a loss of off-site power lines in 1976 and a 1974 sabotage threat that turned out to be a hoax.

4.5.1.4 Radioactivity release summary of reportable events. Table 4.8 gives a summary by year of the total radioactivity released from San Onofre Unit No. 1. Only three radioactivity releases resulted in reportable events. There were no releases in excess of the Tech. Spec. limits.

The first reportable event reporting a radioactivity release occurred while pumping out a radwaste tank on June 28, 1967. Radioactive liquid was being pumped through a monitor tank which had a faster pump-out rate and a low-level cutoff which must be reset manually. The operator was called away during the operation and could not reset the cutoff, resulting in the tank's overflowing. The overflow was routed to the reactor auxiliary building sump, which on high level is automatically pumped to the decontamination drain tank. This tank also overflowed causing the sump to backup through the floor drains, flooding the lower levels of the auxiliary building.[19]

The second radioactivity release event occurred during November 1967. Draining primary loops to replace defective resistance temperature deflectors transferred considerable radioactive crud to the liquid waste tanks. Spills near the coolant drain tank caused smears to reach 538,820 DPM/sq. ft.

Finally on March 5, 1976, during the testing of the spent fuel cask and air pallet system, radioactive contamination was spread to clean areas of the plant. A temporary clean area became contaminated by the scatter of dry material during the handling of the spent fuel cask head. A smear survey revealed that contamination had been spread to the maintenance shop, the turbine plant, and the administration building. Only one employee, the supervisor of plant maintenance, had evidence of personal contamination. A decontamination team cleaned all contaminated areas.[20]

4.5.1.5 Environmental impact summary of reportable events. There were 33 environmental events reported at San Onofre other than the radioactivity release events. Sixteen of the events resulted from the loss of or failure to take environmental data. This lack of data resulted from numerous causes and were not attributable to a single type of failure. Eleven earthquakes were sensed at San Onofre. None of the earthquakes

Table 4.7. Summary of causes of reportable events at San Onofre 1

Cause	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Administration						1						2		3	1	6	13
Design		2	2	2					1	3	2	2	1		5	5	25
Fabrication		2		1		1					2	2			2	1	11
Inherent failure		7	10	20	16	10	14	9	10	17	18	8	13	14	15	15	196
Installation		2	2					1			2	2		5	5	2	21
Maintenance	1	1	1	1		2					1	1	1		6	3	18
Operator		3			1		2	2		3	2	1	1	4	3	1	23
Weather											1		1		2		4
Other			1	1	1	3		4	1	1	3		1				16

Table 4.8. Summary of radioactivity released at San Onofre Unit No. 1

	1967[a]	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981[f]
Airborne															
Total noble gases	4.02E+00[b]	4.83E+00[b]	2.56E+02[d]	4.2E+02	7.67E+03	1.91E+04	1.10E+04	1.78E+03	1.11E+03	4.16E+02	1.54E+02	1.81E+03	6.05E+02	1.05E+03	1.10E+01
Total I-131	NA	NA	NA	NA	NA	4.43E-05	4.20E-01	1.88E-04	4.50E-03	4.13E-03	1.81E-04	2.21E-04	1.22E-04	2.33E-04	7.46E-04
Total halogens	NA	NA	NA	NA	NA	4.42E-05	6.5E-01	2.31E-04	2.45E-01	4.48E-03	1.81E-04	2.21E-04	1.22E-04	2.53E-04	1.44E-03
Total particulates	NA	NA	NA	NA	NA	4.30E-04	1.2E+00	8.74E-05	3.58E-02	1.82E-05	4.83E-06	2.50E-03	2.10E-05	8.41E-01	9.35E-03
Total tritium	NA	NA	2.47E+00	2.09E+01	5.36E+01	2.81E+02	2.69E+02	9.14E+01	3.43E+01	4.72E+01	7.57E+01	5.75E+01	2.82E+01	3.69E+01	4.70E+00
Liquid															
Total mixed product	3.17E-01[c]	1.64E+00[c]	8.00E+00[e]	7.60E+00	1.54E+00	3.03E+01	1.60E+01	5.04E+00	1.22E+00	7.43E+00	9.84E+00	1.10E+01	1.10E+01	1.12E+01	4.41E+00
Total tritium	NA	NA	3.53E+03	4.80E+03	4.57E+03	3.48E+03	4.07E+03	3.81E+03	4.00E+03	3.39E+03	1.79E+03	2.50E+03	2.32E+03	1.03E+03	1.41E+01
Total noble gases	NA	NA	NA	5.59E+01	3.06E+01	5.43E+00	5.36E+01	3.37E+00	4.77E+00	1.26E+01	4.81E+00	1.08E+01	1.81E+01	2.90E+00	NA
Solid															
Total	NA	1.13E-01	4.05E+00	1.05E+01	1.19E+00	7.97E+01	3.81E+02	2.30E+02	2.60E+01	6.98E+02	6.02E+01	7.17E+00	9.24E+01	4.35E+02	6.20E+02

NA - not available.

[a] Period covers June through December 1967.

[b] Reported as total liquid release.

[c] Reported as total gaseous release.

[d] Reported as total beta and gamma activity of gaseous releases.

[e] Reported as total beta and gamma activity of liquid releases.

[f] First six months of 1981 only.

caused equipment damage. Five events were impingement of fish or debris on the intake screens. The final event was a brush fire which knocked out offsite power lines and is discussed in Sect. 4.5.2.3.

4.5.2 Review of significant events

The analysis of the operating history of San Onofre examined reportable events using the criteria described in Section 3.2 for potentially and conditionally significant events. These reportable events were then considered significant by this review if they met one of these criteria:

1. an event in which the failure or failures initiated a design basis event (DBE) as listed in Table 3.1, or
2. an event in which the failure or failures compromised a function of the engineered safety features.

Twenty-two events at San Onofre met the significance criteria above. Table 4.9 summarizes the significance categories from Table 3.3 for these events. The total in the table is 32 because 9 of the events required two significance categories to describe the event. The events designated as significant are discussed below and are grouped as:

1. loss of safety injection system function (3),
2. failure of salt water cooling flow (1),
3. loss of offsite power (3),
4. loss of emergency AC power supply (3),
5. cable tray fires (2),
6. loss of boric acid injection path (2), and
7. instrumentation channels fail due to flooding (2).

In addition, six of the significant events were DBEs reported as reportable events and are discussed in Sect. 4.4. Table 4.10 summarizes all significant events discussed.

4.5.2.1 Loss of safety injection system function. Two reported events presented potential failure of the safety injection system at San Onofre. In addition, in 1981, an actual failure of the safety injection system occurred when a demand was present.

In the last month prior to power operations in 1967, both safety injection recirculation pumps were declared in operable during megger testing. Moisture penetration of the motor windings caused the pumps to fail the test due to low resistance to grounding. The pumps were removed from service, the windings were dried out and potential sources of in leakage were sealed to assure submerged operation.[21]

In 1975, Southern California Edison Company (SCE) and Westinghouse reviewed the design of the San Onofre Unit No. 1 safety injection system. On February 28, 1975, Westinghouse notified SCE of a potential single failure which could prevent the safety injection system from satisfying its design requirements for some accident situations. Specifically, failure of one of the two feedwater pump discharge valves to close might have resulted in a portion of both trains of the safety injection flow being diverted to the steam generators.

Table 4.9. Summary of significant event categories at San Onofre Unit No. 1

	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
S1 - Two or more failures in redundant systems		1	1					1		2	1				2	1	9
S2 - Two or more failures due to a common cause		1	3					1	1						1	2	8
S3 - Three or more failures			2												1		3
S7 - Greater threat to plant safety with different plant conditions or the advent of another credible occurrence															1	2	4
S9 - Other				1		2	2	1		1					1		8
	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total		2	6	1		2	2	3	1	3	1				7	4	32[a]

[a] A total of 22 events were identified as significant with more than one significant category assigned per event for some events.

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Table 4.10. Tabulation of reportable events categorized as significant for San Onofre Unit 1

Report no.	Event date	Report no.	Significant category	Event description	Discussed in section
67-04	6/2/67	7/15/67	S1, S2	Both safety injection recirc. pumps removed for repair after failing megger testing	4.5.2.1
68-03	2/7/68	2/26/68	S2, S3	Minor cable tray fire	4.5.2.5
68-07	3/12/68	4/8/68	S2, S3	Cable tray fire resulted in 5 month shutdown, also boron injection failure	4.5.2.5
68-14	10/14/68	11/25/68	S1, S2	No flow from boric acid transfer pumps due to boron crystallization	4.5.2.6
69-08	7/15/69	10/27/69	S9	Boric acid injection pump plugged due to boron crystallization	4.5.2.6
A071-06	6/22/71	Monthly report 6/71	S9	Loss of two off-site power lines and subsequent turbine overspeed	4.4.3.2
A071-10	7/12/71	Monthly report 8/71	S9	Generator out-of-step condition results in turbine overspeed	4.4.3.2
A072-07	4/30/72	5/9/72	S9	Excessive feedwater flow due to regulating valve failure	4.4.2.1
72-03	7/29/72	8/28/72	S9	Turbine overspeed occurs due to loss of generator field	4.4.3.2
SI 73-08	6/7/73	7/6/73	S1, S2	Loss of off-site power and failure of one diesel generator	4.5.2.3
SI 73-13	10/21/73	10/22/73	S9	Overcooling event causes transient requiring safety injection	4.4.2.1
SI 74-06	7/7/74	7/15/74	S2	Reactor trip due to flooded detector thimbles	4.5.2.7
SI 75-06	2/28/75	3/31/75	S9	Potential safety injection failure due to single failure found	4.5.2.1
SI 75-17	8/12/75	9/12/75	S1	Diesel generator #1 overheats	4.5.2.4
SI 75-18	8/13/75	9/12/75	S1	Diesel generator #2 overheats	4.5.2.4
SI 76-02	1/21/76	2/25/77	S1	Loss of offsite power due to brush fire	4.5.2.3
LER 80-02	1/16/80	1/28/80	S9	Construction worker caused feswater pump trip	4.4.2.4
LER 80-06	3/10/80	3/24/80	S1, S3	Loss of salt water cooling flow	4.5.2.2
LER 80-15	4/22/80	5/5/80	S7	4 kV and 480 V onsite and offsite power lost	4.5.2.3
LER 80-16	4/20/80	5/20/80	S1, S2	Source range monitor fails due to flooding	4.5.2.7
LER 80-38	11/22/80	12/9/80	S7	AC power to station auxiliaries lost	4.5.2.3
LER 81-20	9/3/81	9/14/81	S1	Safety injection valves fail to open disabling safety injection	4.5.2.1

Safety injection for San Onofre Unit No. 1 requires realignment of the main feedwater pumps. Rather than taking suction from the condensate discharge, they received borated water from the refueling water storage tank, pumped by two safety injection pumps. The feedwater pumps' normal discharge to the steam generators must close and injection valves must open to provide a path to the three reactor vessel cold legs.

The Westinghouse analysis showed that if one of the two motor-operated valves in the normal discharges from the feedwater pumps did not close, portions of the flow from both pumps could be diverted to the steam generator. For accidents where the secondary system pressure was lower than the reactor coolant pressure, the situation offered the greatest potential for failure of safety injection.

Administrative controls were initiated to mitigate the potential for this single point failure of the safety injection system. Design changes were scheduled for the next refueling outage. Subsequent requirements by the NRC resulted in additional single failure analyses of the safety injection system and extensive modifications.[22-23]

On September 3, 1981, the unit was operating normally at 390 MW(e), 87% reactor power. A voltage regulator failure caused erratic instrument indications and the operators manually tripped the reactor. In the transient following the manual trip, a valid safety injection actuation signal was received. However, both safety injection valves HV 851 failed to open thereby preventing safety injection flow, had it been required. Tests confirmed that the valves did not meet design requirements and would not open under the design differential pressure. Design changes to correct the problem were evaluated, approved by the NRC and have been implemented. Also, augmented surveillance testing of the valves was instituted.[24]

4.5.2.2 Loss of salt water cooling flow. On March 10, 1980 while operating at 100% power, San Onofre Unit No. 1 experienced a complete loss of flow from the salt water cooling system. The salt water cooling system is the ultimate heat sink for the component cooling water (CCW) system, which serves to cool certain safety-related equipment. The event involved a triple failure consisting of (1) shearing of the south salt water cooling pump shaft, (2) failure to open of the north salt water cooling pump discharge valve, and (3) failure of the auxiliary salt water cooling pump air priming system. As a result, the plant was totally without salt water cooling flow for ten minutes, at which time an operator cross connected the screen wash pumps to provide salt water flow to a CCW heat exchanger. This limited the CCW temperature rise (from 66°F to 82°F in the ten minutes) and bought the equilibrium temperature down to 70°F. The screen wash pumps are not classified as safety-related equipment.

At 41 minutes into the event, the auxiliary salt water cooling pump was restored to service and flow through it to an in-service CCW heat exchanger began seventeen minutes later. Throughout the event, the unit remained at or near full power. A power reduction was initiated at first, but then stopped with only a 3 MW power decrease. The NRC cited the plant for two technical specification violations in this event.[25-26]

Another event involving the salt water cooling system occurred on July 28, 1980. When the south cooling water pump was placed in operation, the pump discharge air-operated valve failed to open automatically. The operator in attendance opened the valve manually and flow was established.

As a test, the pump was shutdown, allowing the valve to close automatically. On restart of the pump, the valve again failed to open. The salt water cooling flow requirements for the plant were met by the north salt water cooling pump throughout the event.

Review of the history of the valve that failed indicated that problems had existed with it since the preventive maintenance overhaul of June 29, 1980. The maintenance action involved conversion of the air operator from AC to DC solenoid operation. This was considered equipment repair rather than a modification, so was not subject to design change reviews. Plant personnel were counseled concerning the procedures that should have been followed for such modifications. Also a new DC solenoid valve was installed in the air operator.[27]

Although not in the original time frame for this examination of operating experience, three more events involving the salt water cooling system occurred in 1982 and are discussed here. On May 13, 1982, two more complete losses of salt water cooling system flow occurred during maintenance. During these events, the unit was in cold shutdown. The events were due to flooding of the intake structure caused by inadequate maintenance procedures.[28] On August 13, 1982, flow from the operable north salt water cooling pump was diverted through the idle south pump. This occurred due to unexpected opening of the south pump's discharge valve. An operator immediately closed the valve and no observable reactor coolant system temperature increase occurred.[29] On August 19, 1982, with the south saltwater cooling pump still out of service, the north pump had to be removed from service due to a smoking motor bearing. Necessary flow to the CCW heat exchangers was maintained by the auxiliary salt water cooling pump, which although connected to an emergency bus, does not meet all seismic qualifications.[30]

4.5.2.3 Loss of offsite power. AC power is essential for maintaining the reactor in a safe condition for most operating situations. Three losses of offsite power were reported for San Onofre, one resulting in no source of AC power being immediately available. These events are described below, along with a partial loss of offsite power that resulted from common cause faults of multiple power lines.

On June 7, 1973, a loss of offsite power occurred at San Onofre with subsequent failure of the No. 1 diesel generator. The reactor was in a refueling outage and the C auxiliary transformer was down for maintenance. The station's auxiliary power needs were supplied by the main transformer and the A and B auxiliary transformers. The main generator neutral current transformers had been shorted and grounded in preparation for performing the high potential test on the main generator.

At 1:56 a.m., June 7, the east vacuum pump was started. At that instant the Unit 1 main transformer relayed due to C phase differential protection. This caused a loss of offsite power, de-energizing the 4 kV and 480 V buses. At 1:59 a.m., the No. 1 and No. 2 diesel generators were started and connected to the 480 V auxiliary buses. Essential equipment including the residual heat removal pumps were restarted.

At 2:50 a.m., the No. 1 diesel generator voltage control failed causing the No. 2 diesel to trip on overload. The No. 1 diesel was removed from service. The No. 2 diesel was restarted and the bus re-energized. It was determined that the unit differential relay operation was due to the ground wire for the main generator current transformers being applied to the differential relay terminals, a maintenance error. This situation was corrected and the main generator was re-energized without further incident. At 6:55 a.m., the station auxiliary power system was returned to normal and the diesel generator was stopped.

In addition to the maintenance error which disabled offsite power, there was a failed capacitor in the No. 1 diesel generator. The capacitor was replaced and the diesel was operable at 6:25 p.m. on June 7, 1973.[31]

On January 21, 1976, the reactor tripped at 4:19 a.m. due to concurrent loss of two offsite power lines. The Santiago-San Onofre and Chino-San Onofre 220 kV lines both relayed open due to a brush fire beneath them. This common cause loss of two lines recurred intermittently during the day as the lines were returned to service and relayed again due to the fire. The system disturbances also opened other lines including two 138 kV lines to San Onofre. Offsite power to the plant was maintained throughout the day and the reactor returned to critical operation at 9:29 a.m. and full load operation at 4:30 p.m.[32]

For a 4 min period on April 22, 1980, all AC power to plant equipment was unavailable. The unit was in cold shutdown for refueling, with AC power to the site supplied through one 220 kV circuit breaker in the switchyard to the A and B auxiliary transformers. Auxiliary transformer C and the No. 1 diesel generator were out of service for maintenance. Both safeguard load sequencing systems were also out of service.

At 11:07 a.m., a test technician performing routine relay testing on auxiliary transformer C failed to block open a set of relay contacts which subsequently tripped the 220 kV circuit breaker supplying power to the site. This resulted in a loss of power to all the 4 kV and 480 V buses. The inservice diesel generator (No. 2) was manually started by the control room operator. However, offsite power was restored at 11:11 a.m., prior to loading the diesel. After verifying the trip was not due to equipment failure, the 220 kV circuit breaker was reclosed.

During the 4 min period, no power was available to the charging pump, residual heat removal pumps, component cooling water pumps or the salt water cooling pumps. However, no significant temperature increases were noted during the event.[33]

On November 22, 1980, with the reactor in cold shutdown and the reactor coolant system drained to mid loop, AC power to two 4 kV buses was momentarily lost. This resulted in a 15 second interruption of power to the operable CVCS charging pump, the residual heat removal pumps the component cooling water pumps and the salt water cooling pumps. However, no significant temperature increases were noted in any of these systems during the incident.

At the time of the incident, the main transformer and auxiliary transformers A and B had been returned to service and switching had been performed to transfer 4 kV buses 1-C and 2-C from auxiliary transfer C to auxiliary transformers A and B. During the transfer however, the control operator had inadvertently opened the bus tie breakers. This allowed 4 kV breakers 1-C and 2-C to become de-energized when auxiliary transformer C was de-energized. Power was restored within 15 seconds by re-energizing auxiliary transformer C. Both diesel generators started automatically but were not required.

The event was the result of an error by a licensed operator. The event was reviewed with the plant operators to preclude recurrence.[34]

4.5.2.4 Loss of emergency AC power supply. A potential loss of emergency AC power was revealed when each of the two diesel generators failed during the semi-annual testing conducted in August 1975. The test requires both diesel generators be operated at rated load for 1 h. This is in addition to weekly and refueling outage testing.

During the test conducted on August 12, 1975, the No. 1 diesel generator tripped due to high cooling water temperature after 35 min of operation. The radiator heat exchanger air passages were blocked with corroded portions of the radiator cooling fans. To correct the problem the radiator was cleaned and the diesel generator tested satisfactorily.

On the next day, August 13, 1975, the semi-annual test of the two diesel generators was conducted again. On this occasion, the No. 2 diesel generator tripped due to high cooling water temperature after 20 min of operation. Investigation revealed that the cap closure on the coolant system standpipe was leaking. The cooling system was not maintaining sufficient pressure and coolant to operate properly. The leakage was routed to a drain and was not observable to operating personnel. A repair of the leak was made, and the drain line was modified to allow identification of leakage.[35]

An actual loss of emergency power generation capacity occurred on November 19, 1981. With diesel generator 2 shutdown to annual maintenance, diesel generator 1 failed to start, tripping on overspeed. Maintenance of diesel generator 2 was halted and it was returned to service and started within the two hour Tech. Spec. limit.

The failure to start of diesel generator 1 was due to low governor oil level, which resulted following preventive maintenance. No evidence was found of oil leakage from the governor. Procedures for checking oil level had not required the oil level check to be made during engine operation, as required by the manufacturer.[36]

4.5.2.5 Equipment disabled by cable tray fires. On two occasions, San Onofre Unit No. 1 experienced cable tray fires which affected power and control cables to a number of plant systems. On February 7, 1968, a fire occurred in cables leading to a penetration. Prior to the event, the unit was in power operation. The 480-V bus ground alarm initiated, indicating a 100% ground on the No. 1 480-V bus. A loud noise was heard and a security officer reported a fire at the southeast side of the containment sphere. Heating and ventilating alarms sounded. Fire fighters controlled the fire within 5 min. The No. 1 and No. 3 480-V buses were connected resulting in both buses indicated grounding. By opening various breakers, the ground was cleared when the Group C pressurizer heater breaker was opened. At this point, a power reduction was initiated to remove the unit from service.

Inspection revealed that the penetration and 65 cables were damaged by the fire. The cables were located in two cable trays one over the other. No damage was found inside containment, either to the connectors or cables. The cause of the fire was determined to be overloaded and overheated cables for the pressurizer heaters. The damaged cables were replaced with larger size cables and ventilation of the penetration area was improved. The total down time for the unit was 286 h and 44 min.

On March 12, 1968, the second cable tray fire occurred. While at power operations, various alarms sounded, including a 480-V system ground. The operator attempted to identify the cause of the alarms. Within 5 min, smoke was reported coming from the No. 2 480-V switch-gear room. Fire was observed in three cable trays in the room and 13 min into the event the reactor was manually tripped. Assistance in fighting the fire was provided by the Marine Corps fire department and the fire was extinguished 35 min after being reported.

During the fire, the diesel generator feed cables were identified as the source of the ground on the No. 2 480-V bus but since the ground was between the breakers and the bus, the entire bus was removed from service. This disabled a large number of undamaged electrical items. In fighting the fire, the fire pumps failed to start and alternate pumps were made available.

A plant cooldown was started and since power was lost to the boric acid injection pump, the boric acid transfer pump was utilized for boration. Four hours into the cooldown, the cooldown was halted because the boron concentration was decreasing rather than increasing due to blockage of the transfer pump flow by boric acid crystals. Alternate boration was provided and the cooldown completed. Damage from the March 12th fire included 185 electrical circuits, sections of three cable trays, 18 control transformers, knife switches in pressurizer heat cabinet, heating and ventilating annunciator panel and smoke damage to certain other equipment.

Investigation after the second fire altered the assessment of the cause of the two fires. Undersize cabling for the pressurizer heaters remained a contributing factor but also considered important was mechanical overloading of cables in crowded cable trays. This contributed to the thermal overloading that caused the fires. Corrective actions were extensive, requiring addition of cable trays, rerouting of cables, cable upgrading and replacement, and changes in electrical fault isolation. The unit returned to service Sept. 8, 1968.[37]

4.5.2.6 Loss of boric acid injection paths. During the shutdown following the fire of March 12, 1968, cooldown was halted due to failure to inject boron for reactivity control (see Sect. 4.5.2.3). The cause given was suction line blockage by boric acid crystals. This caused failure of the boric acid injection pump and both boric acid transfer pumps.

On October 14, 1968, the unit again experienced blockage of the boric acid injection pump and both boric acid transfer pumps. Periodic recirculation flow and improved heat tracing were identified as necessary for adequate system operation.[38]

A similar event occurred on July 15, 1969 when the boric acid injection pump discharge became clogged with boric acid crystals. Temperatures in the discharge piping were found to be 110°F at one point, while precipitation occurs a temperatures below 130°F. Installation of a recirculating pump and raising the heat tracing system setpoint was accomplished to correct the problem.

Other occurrences of single failures due to boric acid crystallization were reported (SI 74-03, LER 76-07, and LER 77-06). However, no losses of injection capability were noted.

4.5.2.7 Instrumentation channels fail due to flooding. On two occasions at San Onofre, failure of multiple instrumentation channels occurred due to flooding.

Failure of two power range instrument channels due to flooding caused an inadvertent reactor trip on July 7, 1974. The reactor trip occurred due to an indication of overpower on nuclear instrument channels 1206 and 1207. Three other instrument channels failed also.

At 10:15 a.m., a routine auto start test of the turbine plant cooling water pumps was conducted. A flow disturbance during the test failed two gaskets in a control rod drive mechanism cooling fan. There was no knowledge of the failure at this time. By 10:50 erratic instrument readings and control rod drive mechanism temperatures indicated a cooler leak. As action to secure the leakage was taken, the reactor tripped due to the overpower indication. Other channels indicated no over power condition actually existed. However, due to the number of channels affected, boration of the reactor was initiated.

A total of 3400 gal of water leaked through the cooler gaskets. Of this amount, ~140 gal collected in the detector thimbles. All affected instrumentation was inspected and replaced as necessary. A design change was accomplished to provide additional drainage for the coolers involved.[39]

During refueling operations on April 20, 1980, two source range instrumentation channels failed. Although alternate channels were available for indication of neutron level, no audible alarm was operable as required. Refueling operations were suspended to allow repairs to be accomplished.

Investigation revealed leakage through the seal between the reactor vessel and reactor cavity. The leak allowed water to enter the neutron detectors and PVC amps. The refueling canal was drained, the seal repaired. The detectors and alarms repaired and replaced in service.[40]

4.5.3 Recurring problems in reportable events

In addition to the individually significant events, the review of the reported events at San Onofre Unit No. 1 identified five areas in which problems recurred over portions of the operating history. These five problem areas were:

1. inverter failures and losses of vital bus power,
2. steam generator tube leaks,
3. dilution of primary coolant,
4. tsunami gate closure, and
5. erroneous control rod indications.

Erroneous control rod indications are discussed in Sect. 4.4.3.4.

4.5.3.1 Inverters and vital bus power. There were 21 occurrences of the momentary loss of vital bus power, causing five shutdowns and nine power reductions. As illustrated by Fig. 4.4, these events occurred in the period from 1969 to 1979. Inverter failures caused all but one of the losses of vital bus power. The exception was a phase-to-phase short in 1979.

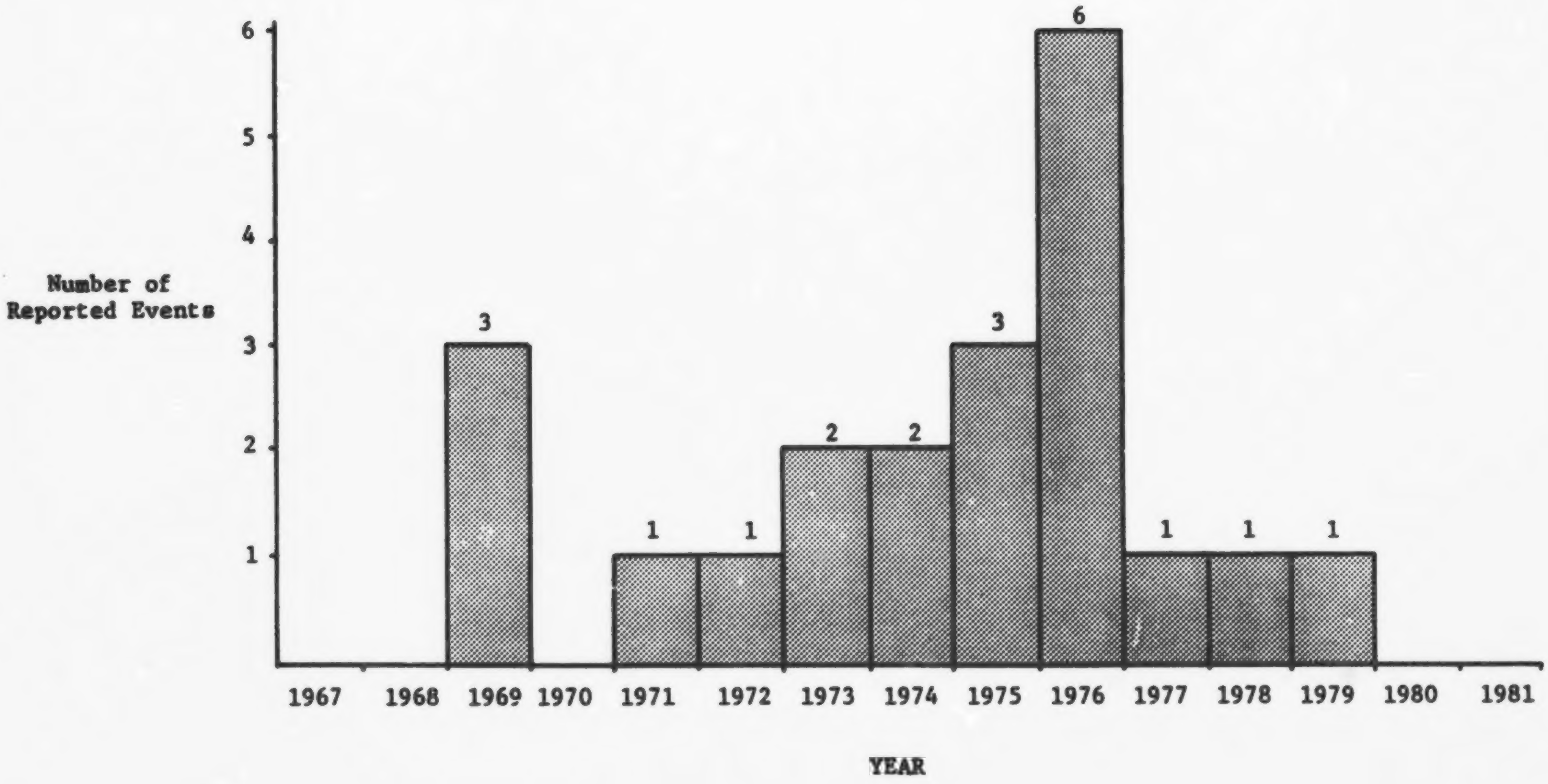

Figure 4.4 Number of Partial Vital Power Losses

The first vital power loss occurred on March 5, 1969. The No. 1 vital bus transferred to its back-up power supply when the No. 1 inverter experienced a fuse failure. This interruption resulted in a nuclear dropped rod signal and initiated a unit load decrease.

A turbine runback occurred on November 24, 1969 when blown fuses failed inverter No. 3. The load runback was terminated manually and the blown fuses were replaced. Maintenance personnel found no cause for the blown fuses.

On December 18, 1969, the failure of No. 2 vital bus inverter initiated a turbine runback. The inverter failure was triggered by a failed power switch in the control rod position recorder. The unit resumed 450 MW(e) operation the same day.

The No. 4 inverter failed on March 23, 1971, indicating a dropped rod. Investigation revealed a shorted capacitor in the transformer circuit. The capacitor was replaced and inverter No. 4 returned to operation.

The No. 3 vital bus transferred from the No. 3 inverter to its emergency power source on December 9, 1972. The transfer caused a momentary power loss to nuclear instrumentation channel 1207, leading to a nuclear dropped rod indication. Investigation revealed that the inverter low voltage power supply had failed.

On January 10, 1973, the reactor tripped when No. 4 vital bus was transferred from the backup power supply to the normal power supply. The control power switch to the No. 4 voltage regulator was inadvertently bumped causing it to open.

On August 17, 1973, the No. 2 inverter, which normally supplies power to power range channel 1205 and the rod position voltage regulator, failed and the load transferred to the backup power source. The resultant voltage transient caused a power reduction with indication of a dropped rod.

The unit reduced power due to a momentary power loss to nuclear power channel 1207 on June 11, 1974. A spare channel drawer was installed in NIS channel 1207 and operated overnight. Three occurrences of channel spiking occurred during the period the spare was in service. However, an operator in continuous attendance at the control console prevented further power reductions. On June 14, 1974, the No. 1 inverter, which normally supplies power to nuclear power range channel 1208, failed and its load transferred to the backup source. The resultant voltage transient caused a spike on channel 1208 which initiated a "Nuclear Dropped Rod Stop." Investigation revealed that a shorted silicon controlled rectifier in the inverter caused the inverter input fuse to open, thus deenergizing the inverter.

While testing a pressurizer level channel on February 19, 1975, a second level channel spiked due to failure of the No. 2 inverter, causing the unit to trip. Investigation revealed that a telecommunications crew, working in the DC switchgear room adjacent to the inverters, bumped the inverter cabinet with the foot of an extension ladder and tripped the No. 2 inverter. The No. 2 inverter would not return to service after the failure. Continued investigation indicated that there was a failed component in the undervoltage logic circuit board that should have caused the

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inverter to trip. Testing of the circuit breaker verified that the undervoltage trip device was sticking. Apparently, bumping the cabinet was all that was required to cause the circuit breaker to operate since the logic circuit board had failed at some prior time.[41]

On April 22, 1975, the No. 2 inverter was returned to service and the No. 2 vital bus was transferred to the No. 2 inverter, which is the normal power supply. During the transfer it was noted that No. 4 vital bus had transferred to its backup power supply. When the No. 4 vital bus was returned to its normal supply, the reactor tripped. Investigation revealed that permissive circuit P-7 was momentarily de-energized during the transfer putting the "at power" trips in service.

An internal short caused an oil-filled capacitor to expand and rupture in the No. 3 inverter on October 19, 1975. A discussion with the manufacturer determined that the failure was random and the voltage rating was more than adequate for the service. The inverter was repaired and vital bus No. 3 returned to inverter power.[42]

On February 9, 1976, a power reduction was initiated when No. 2 inverter was found with zero output, a "fuse open" alarm, and an obviously failed oil filled capacitor. When vital bus No. 2 transferred to its backup power, the ensuing voltage transient caused a spike in nuclear power channel 1205 which initiated a nuclear dropped rod signal.

On February 17, 1976, the No. 4 inverter failed and the load transferred to its backup source. The resultant voltage transient caused a spike on channel 1206 initiating a nuclear dropped rod alarm. No power reduction ensued as unit was operating at less than 70% of full load.

On August 23, 1976, vital bus No. 1 transferred to its backup power source. This transfer was the result of a component failure in the No. 1 inverter. The momentary loss of power precipitated a transfer of all three steam generator feedwater level control systems from their normal power supplies which are fed from vital bus No. 1 to their backup supplies. The backup positive 15 V power source had malfunctioned. The result was a loss of steam and feedwater flow signals to the three steam generator level control systems. Under these conditions the steam/feed water flow mismatch reactor trip was inoperable.

On September 25, 1976, vital bus No. 3 transferred to its backup source resulting in a power reduction. An inspection revealed a failed oil-filled capacitor in inverter No. 3. The ensuing voltage transient caused a spike in the output of a nuclear power range channel, which initiated the nuclear dropped rod runback circuit. A half hour later, vital bus No. 2 transferred to its backup source resulting in a power reduction. The transfer resulted from a fuse failure in No. 2 inverter. The spike in channel 1205 initiated the nuclear dropped rod circuit. Inspection revealed failed components in the No. 2 inverter. Another half hour later, vital bus No. 3 transferred to its backup source a second time resulting in a third power reduction. Investigation revealed a failed capacitor in the No. 3 inverter. This event also was a direct result of a capacitor failure in the AC output filter circuit. Inspection revealed a terminal lug on a cable at one of the inductor terminal evidenced heating and arcing. The cable was improperly terminated resulting in high resistance between the cable and the lug.[30]

During normal operation on June 14, 1977, an inverter dc input fuse opened. A single capacitor bank failed resulting in the failure of an additional capacitor bank and the fuse opening. The redundant supply was available and after all affected parts were replaced, normal power resumed through the inverter.

On June 7, 1978, the same inverter which failed on June 14, 1977 failed again as the result of a capacitor failure. The capacitor failure precipitated the failure of a silicon controlled rectifier and the dc input fuse. All affected components were replaced.

Only one loss of vital power was not the result of an inverter failure. On November 7, 1979, the unit shut down due to the loss of the 480 V bus No. 1. The cause of this event was a rodent bridging two energized phases of the bus.

4.5.3.2 Steam generator tube leaks. After the first five years of operation, steam generator tube leakage became a problem. Beginning in 1972, steam generator tube leaks began recurring, causing 9 forced shutdowns and 17 reportable events.

The single event prior 1972 occurred during construction in 1966. A steam generator was dropped one foot during a lift after it was inside containment. The generator withstood the hydraulic test, but 32 Inconel tubes were deformed and several tube sheets crushed. The damage was repaired and tube plugged. Calculations showed that the plugged tubes would not change plant characteristics.

Leaks from steam generators were identified on February 2, July 19, and October 13, 1972: January 5 1973; April 25, 1974; April 13 and June 11, 1975; July 1, 1979: and July 12, 1980. The most extensive repairs were made during the shutdown which commenced on July 12, 1980 and continued for 4152 h.

Prior to 1976, the problem of steam generator tube leaks was considered to be tube wall thinning around the antivibration bars. However, it was discovered that the antivibration bars were wearing and their integrity compromised. In conjunction with a visual inspection of the "C" steam generator on September 30, 1976, an antivibration bar was removed for inspection. In several locations, the tube had worn into the bar. This problem was corrected by the design and installation of additional antivibration bars with rectangular cross section.[40]

In July 1980, Southern California Edison (SCE) installed leak tight brazed sleeves on tubing identified with significant intergranular attack. Intergranular attack was occurring at the top of the tubesheet for tubes located in the central region of the steam generators. SCE encountered difficulty with implementation of the brazed sleeve joints in deep sludge and developed an alternate design utilizing mechanical joints.[41]

Other problems associated with steam generator tube leaks included dilution of the primary system. The next section discusses that problem.

4.5.3.3 Dilution of primary coolant. On four occasions during extensive steam generator repair, water leakage into the primary coolant system reduced the boron concentration. Operators closely monitored boron concentration, reactor water level and other indicators and stopped the positive reactivity insertion.

The first event occurred on October 1, 1977. At the conclusion of eddy current testing, 13 tubes in the "B" steam generator were explosively plugged. The water level on the secondary side was raised to shield employees working in the area. Approximately one-half hour later the operator noticed the secondary side level had decreased. An additional tube was leaking. The total change in boron concentration was 75 ppm from 1684 to 1609 ppm.[44]

The final three dilutions of the primary system occurred during the steam generator repairs in 1980. On July 5 and 6, 1980 leakage past inflatable seals occurred during decontamination. On two occasions a rise in reactor vessel was noted. Each time work was halted and boron concentration was monitored. A maximum decrease of 400 ppm of boron was measured.[45] On September 1, 1980, water leakage through a feedwater block valve diluted the primary system during steam generator tube inspection. A maximum dilution of 35 ppm occurred.[46] The last primary system dilution occurred on September 22, 1980 and was again the result of leakage past inflatable seals during decontamination. A boron dilution of 55 ppm occurred during this event.[47]

4.5.3.4 Tsunami gate closure. The tsunami gate is the salt water intake stop gate. Its closure cuts off salt water cooling flow. There were three occasions when San Onofre experienced the closure of the tsunami gate. On November 1, 1967, a shorted limit switch caused the gate to close with one circulating water pump out of service. Rupture of the accumulator reservoir tank caused the gate to fail on February 9, 1968. Finally on October 9, 1969, the tsunami gate slipped from its annular bolts and fell into the intake tunnel.

4.6 Evaluation of Operating Experience

This analysis studied 154 shutdowns and power reductions, 327 reportable events and other miscellaneous documentation concerning the operation of San Onofre Nuclear Generating Station Unit No. 1. The objective was to indicate those areas of plant operation which have compromised plant safety. This review identified three problems which should be of continued concern.

The first area involved the safety injection system. Section 4.5.2.1 detailed three events in which the safety injection system was actually or potentially lost. Another reason for concern are the number of random failures associated with the safety injection system. During safety injection, part of the feedwater system is used to deliver water to the reactor core. Some failures of the feedwater system would also affect the function of those components in their safety injection role. If the number of times the safety injection system was involved were combined with the number of times the feedwater system was involved, the combination would have the largest population of failures in reported events (see Table 4.5 in Sect. 4.5.1.2). Regardless of the total number of events, it is an area that may require further investigation.

The second problem area identified in this review of operating experience is the continuing problems with the salt water cooling system. The event resulting in total loss of salt water cooling flow would have been a more serious event if it had occurred during the early stages of residual heat removal operation. Also, the continuing problems with the system in 1982 indicate a need for close examination of the system.

The final area for potential continued failures involved inverter failures. A single inverter failure has little consequence. However, with the number of failures exhibited at San Onofre Unit No. 1 the potential for concurrent failures is greatly enhanced.

Steam generator and condenser tube leaks continued to plague San Onofre through 1981. Associated with major steam generator repairs, dilution of the reactor coolant boron concentration also continued to recur during 1980. Other problems such as dropped control rods, pressurizer relief valves, turbine overspeed and tusunami gate closure occurred only over short periods of time and were solved.

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Appendix A: San Onofre Unit No. 1

Part 1. Forced shutdown and power Reduction Tables

Table A1.1 1967 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1967)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	7-9	N/A	0		While performing operator training start-ups with the reactor, unexplained rod drops occurred in subgroup 4 of control rod group No. 1. Investigation revealed that a timer relay was malfunctioning.	A	3	Reactor (RB)	Relays	D4.3
2	7-17	1080	13	LTR 8/67	During turbine overspeed testing, salt leaks were noted in the condenser. Inspection of turbine revealed significant blade damage. All of the blades in the four last stage rows were replaced.	A	1	Steam & Power (HA)	Turbines	N1.1.4
3	9-11	192		LTR 11/20/67	Unit shutdown due to excessive circulating water pump vibration and leaking pressurizer spray valve. Upon investigation, high circulating water pump pressure and high pressure differential across the condenser were also detected. Also the system was pulling in an excessive amount of marine growth following a heat treat of the circulating water system the previous day.	A	1	Steam & Power (HF) Reactor Coolant (CB)	Pumps Valves	N3.1
4	10-1	216		LTR 10/9/67	Repair of leak on east main steam line maintenance block valve bypass valve. Also two pressurizer power relief valves were also repaired.	A	1	Steam & Power (HB) Reactor Coolant (CB)	Valves	N3.1

Table A1.1 (Continued)

No.	Date (1967)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
5	10-10	144	30		Reactor tripped by inadvertent signal in the variable low pressure trip channel. Occurred while circuitry was being tested with one channel placed in the trip mode for testing.	G	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
6	10-19		75		Unit taken off line due to false indication of inserted control rod.	A	1	Reactor (RB)	Instrumentation & Controls	N2.4
7	11-1	24	90	LTR 12/11/67	With one circulating water pump out of service, the unit was manually tripped due to an inadvertent closure of the tsunami gate. A shorted limit switch was found to be the cause of the closure.	A	3	Steam & Power (HF)	Circuit Closers/ Interrupters (Switches)	N1.1.4
8	12-5		85		Reactor tripped on incorrectly set overpower set point.	G	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N6.1
9	12-12	12		LTR 1/15/68	Unit was manually tripped when five control rods in subgroup 7 were dropped. Defective electrical components replaced.	A	2	Reactor (RB)	Instrumentation & Controls	D4.3

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Table A1.2 1968 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1968)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	1-24	72			Unit taken off line for containment inspection after increased radiation level was detected in the sphere. Inspection of the sphere revealed two leaking RTDs on the "A" coolant loop and the packing glands on the pressurizer spray valves leaking.	A	1	Reactor Coolant (CB)	Valves Instrumentation & Controls	N3.1
2	2-7	286	95	LTR 2/26/68	Reactor manually tripped after fire was observed in sphere electrical penetrations. Probable cause was overloaded power cables for the pressurizer heaters.	A	2	Reactor Coolant (CB)	Heaters, Electric Electrical Conductors (Cable)	N1.1.4
3	3-4	6			Cleaning of the rod control slave cycler contacts was in progress and the subgroup #6 slave cycler had been replaced with a shutdown cycler so that the contacts could be cleaned. An attempt was made to cycle the rods one step and subgroup #6 was dropped to 160 steps. The slave cycler was examined and no reason for the failure was found.	G	3	Reactor (RB)	Control Rod Drive Mechanisms	D4.3
4	3-9	43		LTR 4/68	Unit taken off line when physics data indicated a bottomed control rod. Investigation revealed that the the polarity of the movable gripper coil had been reversed during repairs to penetration EPC-4.	G	3	Reactor (RB)	Control Rod Drive Mechanisms	D4.3

Table A1.2 (Continued)

No.	Date (1968)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
5	3-12	4332	90	LTR 4/8/68	Unit manually tripped after a fire occurred in a cable tray in the switchgear area. Probable cause was overloaded pressurizer heater cables.	A	2	Reactor Coolant (CB)	Heaters, Electric Electrical Conductors (Cable)	N1.1.4
6	9-9	43			While preparing to roll the turbine all five rods in subgroup 7 slipped from 117 to 40 steps and the reactor tripped immediately. Probable cause was traced to BF relays in rod control system racks.	A	3	Reactor (RB)	Control Rod Drive Mechanisms	D4.3
7	9-19	152		LTR 12/68	Unit removed off line to repair the letdown isolation valve packing, replace three failed reactor coolant system RTDs, adjust the load runback arming point and perform other minor maintenance. Also reactor coolant pump "A" was found rotating backwards as a result of the anti-rotation pawls not properly engaging. These were modified on all three pumps.	A	1	Auxiliary Process (PC) Reactor Coolant (CB)	Valves Instrumentation & Controls Pumps	N1.1.4
8	9-26	87	33	LTR 12/68	Unit manually tripped when control rods in subgroup 8 dropped into the core while a slave cycler failure alarm was being cleaned. (This occurred when an operator manually opened, closed, and reopened the half-power contactor while attempting to clear a slave cycler failure alarm.) The cause of the slave cycler failure was due to improper operation of the slave cycler clutch.	A	2	Reactor (RB)	Control Rod Drive Mechanisms	D4.3

Table A1.2 (Continued)

No.	Date (1968)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9	12-28	∼84	100	LTR 2/69	Leakage through the pressurizer relief valve RV-533 was observed on 12-9-68 by increased temperature in valve discharge piping. Continued observation mode until a normal shutdown was initiated.	A	1	Reactor Coolant (CB)	Valves	N3.1

Table A1.3 1969 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1969)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
	1-1	~160			Continuation of outage of 12-29-68, repair of relief valve.	A	4	Reactor Coolant (CB)	Valves	N3.1
1)	1-9	44		LTR 2/69	Unit removed off line after a routine test of the stop valves produced a spurious partial turbine trip alarm. Investigation revealed that the turbine auto-stop oil supply pressure was low due to a badly scored seat and disc in the auto-stop oil dump valve.	A	1	Steam & Power (HA)	Valves	D2.3
2)	3-5	0			Power reduction. Vital bus inverter failure.	A	5	Electric Power (ED)	Inverters	N1.1.6
3)	3-8	14	75		Reactor tripped due to relay malfunction in turbine control valve servomotor. (Replaced the turbine control valve control oil plungers as the original design permitted the control valve servomotors to oscillate at high frequency.)	A	1	Steam & Power (HA)	Relays	N1.1.1
4)	3-22	314	100		Unit shutdown to replace pressurizer safety valves and repair components contributing to reactor coolant system leakage.	A	1	Reactor Coolant (CB)	Valves	N3.1
5)	4-7	0	100-50		Power reduction. Load runback was experienced due to unexplained false dropped rod signal. The load runback pressure switch had drifted.	A	5	Reactor (RB)	Instrumentation & Controls	N2.4

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Table A1.3 (Continued)

No.	Date (1969)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
6)	4-29	6			While heat treating the circulating water system a routine stop valve test was performed. The left hand stop valve failed to reopen and the unit was removed from service. The left hand stop valve auto-stop oil solenoid dump valve had a piece of foreign material in it.	A	1	Steam & Power (HA)	Valves	N1.1.4
7)	6-20	1193			Unit shut down to inspect the turbine-generator and modify the steam generator moisture separators.	B	1	Steam & Power (HA) (HB)	Turbines Heat Exchangers (Steam Generators)	N1.1.1
8)	8-10	80			Unit shut down to correct leakage of three pressurizer relief valves.	A	1	Reactor Coolant (CB)	Valves	N3.1
9)	8-14	86			Reactor tripped when control rods associated with subgroup 7 dropped into the core due to an intermittent open contact of a BF type relay in the rod control logic. Valve maintenance kept the plant shut down for 86 hours.	A	3	Reactor (RB) Reactor Coolant (CB)	Instrumentation & Controls Valves	D4.3
10)	10-9	165		LTR 10/24/69	Unit removed from service due to the intake stop gate (tsunami gate) which had slipped from its anchor bolts and dropped into the intake tunnel.	A	1	Steam & Power (HF)	Valves	N1.1.4

Table A1.3 (Continued)

No.	Date (1969)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
11)	10-28	60		LTR 2/12/70	Unit shutdown to repair the root valves of the pressurizer instrument column.	A	1	Reactor Coolant (CB)	Valves	N1.1.4
12)	11-24				Power reduction. Vital bus inverter failure.	A	5	Electric Power (ED)	Inverters	N1.1.4
13)	12-18				Power reduction. Vital bus inverter failure.	A	5	Electric Power (ED)	Inverters	N1.1.4

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Table A1.4 1970 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1970)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	5-29	2	0	LTR 7/10/70	During startup, the turbine was manually tripped when it was noted that the turbine acceleration was faster than desired. The reactor tripped due to 2 of 4 power channels indicating greater than 10% power.	A	2	Steam & Power (HA)	Turbines	N1.1.4

Table A1.5 1971 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	3-18	8			A reactor trip was experienced due to a spurious signal from Channel I variable low pressure trip circuit while Channel III was in a tripped position for maintenance.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
2	5-1	180			Unit was removed from service to repair a pressurizer spray valve flange leak, replace five reactor coolant system RTDs and to plug reheater tube leaks.	B	1	Reactor Coolant (CB) Steam & Power (HH)	Valves Instrumentation & Controls Pipes, Fittings	N3.1
3	6-22	6		LTR 8/12/71	Unit was tripped by backup overspeed protection when a 220 KV line relayed.	A	3	Electric Power (EA)	Circuit Closers/ Interrupters (Switchgear)	D2.2
4	6-25	28			Unit removed from service to repair the HP turbine extraction drain piping, leak test main condenser tubes, and inspect equipment in the containment sphere.	B	1	Steam & Power (HA)	Pipes, Fittings	N3.2
5	6-27	17			Unit removed from service to repair condenser tube leaks.	A	1	Steam & Power (HC)	Pipes, Fittings	N3.2
6	7-9	32			Unit was removed from service to allow switchyard construction work.	B	1	Electric Power (EB)	Circuit Closers/ Interrupters (Switchgear)	N1.1.4

Table A1.5 (Continued)

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
7	7-12	12			Unit tripped from a generator out-of-step condition.	A	3	Steam & Power (HA)	Heat Exchangers (Steam Generators)	D2.2
8	7-24	30			Unit removed from service to allow switchyard construction work.	B	1	Electric Power (EB)	Circuit Closers/ Interrupters (Switchgear)	N1.1.1
9	10-27	104			Unit removed from service to repair reheater tube leaks and apply epoxy to the condenser tube inlet ends.	A	1	Steam & Power (HH)	Pipes, Fittings	N3.2
10	11-1	3			Unit manually tripped to obtain additional data on turbine overspeed characteristics.	A	2	Steam & Power (HA)	Turbines	N7.0
11	11-3	3			Unit manually tripped to obtain additional data on turbine overspeed charteristics.	A	2	Steam & Power (HA)	Turbines	N7.0
12	11-5	3			Unit manually tripped to obtain additional data on turbine overspeed charteristics.	A	2	Steam & Power (HA)	Turbines	N7.0

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Table A1.6 1972 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1972)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	2/25	7			Unit removed off line for balancing of turbine shaft and mechanical overspeed trip testing.	A	1	Steam & Power (HA)	Turbines	N1.1.4
2)	3/4	4			Unit removed off line to conduct turbine overspeed tests.	A	1	Steam & Power (HA)	Turbines	N1.1.4
3)	3/24	12			Unit removed from service to reset the turbine mechanical overspeed trip set point.	A	1	Steam & Power (HA)	Turbines	N2.3
4)	4/29	~12			Unit removed from service to perform modifications to the main steam control valves.	A	1	Steam & Power (HB)	Valves	N1.1.1
5)	4/30	27	12	LTRs 5/9/72 5/30/72	During startup, the reactor tripped due to a turbine trip on a high steam generator level signal. Failure of positioner of main feedwater regulating valve.	A	3	Steam & Power (HH)	Valves	D1.2
6)	5/18	162			Unit removed from service to inspect the turbine control valves, complete reheater and condenser repairs, and perform miscellaneous maintenance.	B	1	Steam & Power (HA) (HC) (HH)	Valves Heat Exchangers	N3.2
7)	7/19	177			Unit removed from service to repair a tube leak in steam generator C. (On 7/8 a slight increase in radioactive concentration, channel 1216; was noted.) Analysis indicated leak was on "C" steam generator. Sampling began with leak rates calculated through 7/18 when leakage was approximately 100 gal/d.	A	1	Steam & Power (HB)	Heat Exchangers (Steam Generators)	N3.1

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Table A1.6 (Continued)

No.	Date (1972)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8)	7/27	33	0		During startup, the main exciter motor failed mechanically when being started. The problem was determined to be rubbing between the rotor and stator.	A	3	Steam & Power (HA)	Generators and Motors	D2.2
9)	7/29	3	100	LTR 8/28/72	Unit tripped from loss of main generator field.	A	3	Steam & Power (HA)	Generators	D2.2
10)	9/20	4	62		During a "Control Rod Exercise Test" an automatic load limit runback was initiated from "Nuclear Dropped Rod" circuitry. The reactor was manually tripped and the control rod circuitry inspected. Contactors and relays cleaned but no abnormal conditions were found.	A	2	Reactor (RB)	Instrumentation & Controls	N1.1.4
11)	9/20	65		LTR 9/29/72	The reactor was manually tripped after a high temperature alarm was received on the east main feed pump inboard motor bearing. Excessive thrust bearing clearance was found in the pump.	A	2	Steam & Power (HH)	Pumps	N1.1.4
12)	10/13	155			On 9/12/72, analysis determined that the "A" steam generator was experiencing primary to secondary side leakage. Sampling began and continued until 10/13 when leakage was over 100 gal/d. Thus unit removed from service to repair "A" steam generator tube leakage.	A	1	Steam & Power (HB)	Heat Exchangers (Steam Generators)	N3.1
13)	12/9	0	100-60		Power reduction. A transfer of No. 3 vital bus from the No. 3 inverter to its emergency power source caused a momentary power loss to NIS channel 1207 initiating a "Nuclear Dropped Rod" indication.	C	5	Reactor (RB) Electric Power (ED)	Instrumentation & Controls Electrical Conductors (BUS)	N6.3

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Table A1.7 1973 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1973)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/6	108	100	LTR 2/15/73	The unit was removed from service for locating and repairing "A" steam generator tube leaks. (On 11/2/72, analysis indicated a leak existed between steam generator primary and secondary systems.) Sampling began and continued until leak rate was approximately 100 gal/d.	A	1	Steam & Power (HB)	Heat Exchangers (Steam Generators)	N3.1
2)	1/10	1	0		During startup the reactor tripped when No. 4 vital bus was transferred from the backup power supply to the normal power supply. It is believed that the control power switch to No. 4 voltage regulator was inadvertently opened by being bumped.	A	3	Electric Power (ED)	Electrical Conductors (BUS) Circuit Closers/ Interrupters (Switches)	N6.3
3)	2/20	0	?-?		Power reduction. While unit load was being reduced for a condenser tube cleaning outage, observation of the rod position recorder indicated that a control rod had gone from 200 to 145 steps on the recorder.	A	5	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
4)	8/17	0	100-75		Power reduction. Initiated when failure of an inverter caused a load transfer. (Voltage transient)	A	5	Electric Power (ED)	Generators (Inverters)	N1.1
5)	10/21	1974	100	LTR 10/22/73 10/31/73	Unit was being removed from service to investigate turbine problems, indicated by bearing vibration and salt water leakage when a safety injection actuation and reactor trip was experienced. Investigation revealed turbine blade failure.	A	3	Steam & Power (HA) (HC) Engineered Safety Features (SF-C)	Turbines Heat Exchangers (Condensers) Instrumentation & Controls	D1.2

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Table A1.8 1974 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1974)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
	1/1	516			Continuation of the October 21, 1973 outage.	A	4	Steam & Power (HA) (HC)	Turbine Heat Exchangers (Condensers)	D1.2
1)	4/27	547	100		Repair of steam generator and reheater tube leaks and repair of leaking pressurizer safety valve. Prior to shutdown there were indications of a partial loss of fan capacity in generator hydrogen gas blower.	B	1	Steam & Power (HB)	Heat Exchangers (Steam Generators)	N3.1
2)	6/11	0	100-40		Power reduction. Automatic load limit runback initiated by a momentary spike of a nuclear power channel.	A	5	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
3)	6/14	0	100-40		Power reduction. Automatic load limit runback initiated when an inverter which supplies power to nuclear power range channel 1208 failed and its load was transferred to the backup source.	A	5	Instrumentation & Controls (IA)	Generators (Inverters)	N1.1.4
4)	7/7	55	100	LTR 7/15/74	Trip from indicated overpower condition caused by water intrusion into detectors of two power range channels due to gasket failure on cooler of rod drive cooling fan.	A	3	Reactor (RB) Instrumentation & Controls (IA)	Control Rod Drive Mechanisms Instrumentation & Controls	N3.1

Table A1.8 (Continued)

No.	Date (1974)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
5)	7/9	0	70-35		Power reduction. While increasing load there appeared to be a flow restriction in the feedwater line to steam generator "C". Upon investigation, the flapper of the associated check valve was found detached from the arm and lying in the check valve body thus causing a flow restriction.	A	5	Steam & Power (HH)	Valves	N1.1.4
6)	8/20	5	100	LTR 8/20/74	Spurious trip on indicated pressurizer high level while testing level channels.	A	3	Reactor Coolant (CB)	Instrumentation & Controls	N2.4
7)	10/21	7	0		While returning to full load, unit was manually tripped because of dropped rods (control bank 2 slipped into core). No cause found.	A	2	Reactor (RB)	Control Rod Drive Mechanisms	D4.3

Table A1.9 1975 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1975)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/NSIC(N) Event Category
1)	2/19	4	100		While testing a pressurizer level channel, a second level channel spiked due to a failure in the No. 2 inverter. Trip from pressurizer high level.	A	3	Reactor Coolant (CB)	Generators (Inverters)	N1.1.4
2)	4/22	2			While transferring the No. 4 vital bus back to its normal power supply the reactor tripped.	A	3	Electric Power (ED)	Electrical Conductors (BUS)	N6.3
3)	5/21	10	100		Reactor manually tripped from restricted circulating water flow caused by seaweed fouling intake structure.	H	2	Steam & Power (HF)	Pipes, Fittings	N9.2
4)	6/11	127			Shutdown to repair pressurizer safety valves. Also plugged leaking steam generator tube.	B	1	Steam & Power (HB) Reactor Coolant (CB)	Heat Exchangers (Steam Generators) Valves	N3.1

Table A1.10 1976 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1976)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/8	0	100-50		Power reduction. Plug 3 leaking tubes in north half of "A" condenser. Also heat treat circulating water tunnels.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
2)	1/21	7			Loss of off-site power due to fire burning in San Clemente area.	H	3	Electric Power (EA)	Electrical Conductors	N9.0
3)	1/22	0	100-60		Power reduction. Load reduced as a precautionary measure when brush fires reached vicinity of 220 kv transmission lines.	H	5	Electric Power (EA)	Electrical Conductors	N9.0
4)	1/26	0	100-10		Power reduction. Leaking condenser tube in north half of "A" condenser resulted in an increased turbine exhaust backpressure.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
5)	1/29	0	100-50		Power reduction. Plug leaking condenser tube in north half of "A" condenser.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
6)	2/6	0	100-50		Power reduction. Condenser tube leakage corrected	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
7)	2/9	4	100		Spurious spike in pressurizer level caused by inverter problem while second channel was in test.	A	3	Reactor Coolant (CB)	Instrumentation & Controls	N2.4
8)	3/19	0	100-25		Power reduction. Replace internals in "C" steam generator feedwater line check valves.	A	5	Steam & Power (HH)	Valves	N1.1.4

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Table A1.10 (Continued)

No.	Date (1976)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9)	3/23	0	100-50		Power reduction. Investigate condenser salt water in-leakage.	A	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
10)	3/29	0	100-50		Power reduction. Investigate condenser salt water in-leakage.	A	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
11)	4/17	9	33		During startup, spurious turbine trip resulted in a reactor trip.	A	3	Steam & Power (HA)	Turbines	D2.3
12)	4/17	7	33		During startup toward full power, spurious turbine trip resulted in a reactor trip.	A	3	Steam & Power (HA)	Turbines	D2.3
13)	4/18	20	15		Turbine trip due to incorrect setting of an overspeed trip device.	G	3	Steam & Power (HA)	Instrumentation & Controls	D2.3
14)	4/19	6	75		Load was being reduced for preparation of overspeed testing when a faulty thermocouple indicated thrust bearing temperature on east feedwater pump was increasing. Unit removed for overspeed tests and repairs to "B" steam generator feedwater line check valve.	B	3	Steam & Power (HB)	Valves	N1.1.4
15)	6/28	8	100	LER 76-004	While unit at reduced load for heat treating the circulating water system, the "C" loop reactor coolant flow transmitter failed resulting in trip from reactor coolant full load low flow indication.	A	3	Reactor Coolant (CB)	Instrumentation & Controls	N1.1.4
16)	7/2	0	100-75		Power reduction. Plug leaking condenser tube.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2

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Table A1.10 (Continued)

No.	Date (1976)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
17)	7/14	16	100		Repair a control oil leak on the No. 2 turbine control valve.	A	1	Steam & Power (HA)	Valves	N1.1.4
18)	7/30	101	100	LER 76-006	Repair leaking steam generator tubes on "C" steam generator.	A	1	Steam & Power (HB)	Heat Exchangers (Steam Generators)	N3.1
19)	8/7	0	100-60		Power reduction. Relay coil failed which resulted in an erroneous indication of a dropped control rod.	A	5	Reactor (RB)	Relays	N1.1.4
20)	9/25	0	76-70		Power reduction. Failures of No. 2 and No. 3 inverters supplying vital power buses resulted in an erroneous indication of a dropped control rod.	A	5	Electric Power (ED)	Generators (Inverters)	N1.1.4
21)	9/26	0	76-70		Power reduction. No. 3 inverter failed resulting in an erroneous indication of dropped control rod.	A	5	Electric Power (ED)	Generators (Inverters)	N1.1.4

Table A1.11 1977 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1977)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	4/14	26	90		Received two erroneous rod bottom lights. Manually tripped the unit.	A	1	Reactor (RB)	Instrumentation & Controls	D4.3
2)	4/21	27	100		Failure of both reactor cavity cooling fans. Manually tripped the unit.	A	1	Engineered Safety Features (SB)	Blowers (Fans)	N1.1.4
3)	5/18	14	100		Failed gripper coil on control rod group-- dropped four rods. Manually tripped the reactor.	A	2	Reactor (RB)	Control Rod Drive Mechanisms	D4.3
4)	6/9	10	100		Failed moveable gripper coil on shutdown rod group - dropped four rods. Manually tripped the reactor.	A	2	Reactor (RB)	Control Rod Drive Mechanisms	D4.3
5)	6/10	4	90		Inadvertent trip during routine weekly testing of power range NIS instrumentation. An overtrip channel had been reset prior to testing another channel.	G	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N6.1
6)	7/1	0	?-50		Power reduction. Plug leaking tube in south half of "B" condenser.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
7)	7/2	0	?-50		Power reduction. Plug additional tube in south half of "B" condenser.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
8)	8/17	0	100-60		Power reduction. Repair a ground in circulating water pump motor leads.	A	5	Steam & Power (HF)	Motors	N1.1.4
9)	9/9	646	95	LER 77-013	Reactor coolant pump inspection, S/G inspection, S/G plugging.	B	1	Reactor Coolant (CB) Steam & Power (HB)	Pumps Heat Exchangers (Steam Generators)	N3.1

Table A1.11 (Continued)

No.	Date (1977)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
10)	10/6	2	0		Reactor trip breaker undervoltage relay stuck in de-energized position.	A	3	Electric Power (ED)	Relays	N1.1.4
11)	10/6	4	0		Reactor trip breaker undervoltage relay stuck in de-energized position.	A	3	Electric Power (ED)	Relays	N1.1.4
12)	11/19	25	100		Repair SIS recirculation valve.	B	1	Engineered Safety Features (SF-C)	Valves	N1.1.4
13)	12/29	3	95		Repair steam leak on turbine drain line. Turbine generator off-line. Reactor remained critical.	B	9	Steam & Power (HA)	Pipes, Fittings	N3.2

Table A1.12 1978 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1978)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/10	0	100-84		Power reduction. Repair ground on circulating water pump motor leak.	B	5	Steam & Power (HF)	Motors	N1.1.4
2)	3/8	4	95		Reactor tripped from a loss of coolant flow signal. The low flow condition occurred when a power system disturbance (off-site) resulted in low voltage at the reactor coolant pump motors.	H	3	Electric Power (EA)	Pumps	D3.1
3)	3/22	0	100-?		Power reduction. Erroneous signal indicated a dropped control rod.	A	5	Reactor (RB)	Instrumentation & Controls	N2.4
4)	3/29	0	100-46		Power reduction. Repair a condenser tube leak.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
5)	4/5	472	100		Steam generator inspection. (Regulatory Requirement)	D	1	Steam & Power (HB)	Heat Exchangers (Steam Generators)	N8.0
6)	5/16	0	100-66		Power reduction. Grounded rod position indication system component caused on erroneous dropped rod signal.	A	5	Reactor (RB)	Instrumentation & Controls	N1.1.4
7)	6/9	0	100-58		Power reduction. Repair condenser tube leaks. Maintained reduction to defer fuel depletion.	B,F	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2

Table A1.12 (Continued)

No.	Date (1978)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8)	8/15	0	100-83		Power reduction. Repair reheater drain line.	A	5	Steam & Power (HH)	Pipes, Fittings	N1.1.4
9)	8/18	0	100-33	LER 78-010	Power reduction. Reclose a feedwater pump safety injection valve. Valve unexpectedly opened during maintenance.	G	5	Engineered Safety Features (SF-C)	Valves	N6.3
10)	9/12	5	100		Reactor and turbine tripped while performing bearing low oil pressure trip test.	G	3	Steam & Power (HA)	Turbines	D2.3
11)	11/6	4			Spurious steam-feedwater flow mismatch.	A	3	Steam & Power (HB) (HH)	Instrumentation & Controls	N2.4
12)	11/10	10			Instrument malfunction indicating a low flow condition of the reactor coolant system.	A	3	Reactor Coolant (CB)	Instrumentation & Controls	N1.1.4

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Table A1.13 1979 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1979)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	2/23	0	100-70		Power reduction. Plug leaking condenser tubes.	A	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
2)	4/5	82	100	LER 79-002	Repair a major condenser tube leak and the feedwater flow straighteners.	A	1	Steam & Power (HC) (HH)	Heat Exchangers (Condensers) Pipes, Fittings	N3.2
3)	4/22	0	100-33		Power reduction. Repair of a steam leak in turbine steam extraction line.	B	5	Steam & Power (HA)	Turbines Pipes, Fittings	N3.2
4)	5/14	4	100		Unit trip from 2 out of 3 variable low pressure trip channels while performing Delta T and TAVE tests.	B	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N6.3
5)	6/1	394	95	LERs 79-008 79-010	Steam generator tube leak - tubes plugged.	B	1	Steam & Power (HB)	Heat Exchangers (Steam Generators)	N3.1
6)	8/29	10	95		Replace low voltage power supply on #2 sequencer.	A	1	Instrumentation & Controls (IB)	Relays	N1.1.4
7)	8/30	0	100-50		Power reduction. Condenser tube leak.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
8)	9/7	0	100-60		Power reduction. Condenser tube leak.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2

Table A1.13 (Continued)

No.	Date (1979)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9)	9/14	234	100	LER 79-016 79-013	Repair refueling water pump suction piping and replace pipe section on safety injection line.	A	1	Engineered Safety Features (SF-C)	Pipes, Fittings	N1.1.4
10)	10/23	0	100-25		Power reduction. Decreasing condenser vacuum from an open interconnection between condenser and the hotwell.	G	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N1.1.4
11)	11/7	133	100	LER 79-017	Loss of 480V Bus No. 1.	A	2	Electric Power (EB)	Electrical Condustors (BUS)	N1.1.4
12)	11/29	0	100-65		Power reduction. Condenser tube leak.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
13)	11/30	0	100-80		Power reduction. Condenser tube leak.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
14)	11/30	0	100-80		Power reduction. Condenser tube leak.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
15)	12/12	0	100-60		Power reduction. Locate condenser tube leakage.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
16)	12/16	0	100-80		Power reduction. Repair south circulating water pump.	A	5	Steam & Power (HF)	Pumps	N1.1.4

Table A1.14 1980 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1980)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/16	38	100	LER 80-002	Unit tripped from steam flow/feedwater flow mismatch trip caused by construction worker who accidently struck the closing circuit control relay to the east feedwater pump normal discharge valve.	H	3	Steam & Power (HH)	Relays	D2.7
2)	1/26	372	100		Unit off line for TMI modification.	D	1	NA	NA	N8.0
3)	2/11	0	?-60		Power reduction. Turbine low governor oil pressure.	A	5	Steam & Power (HA)	Turbines	N1.1.4
4)	2/12	8	60		Unit off line to repair the turbine governor control oil pressure system.	A	1	Steam & Power (HA)	Turbines	N1.1.4
5)	2/17	0	100-66		Power reduction. Repair salt leak in the condenser.	B	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.2
6)	3/6	11	100	LER 80-011	Unit manually off line to replace pressurizer relief tank rupture diaphragm.	A	1	Reactor Coolant (CB)	Valves	N1.1.4
7)	7/12	4152	0	LER 80-014	Steam generator tube repair. Continuation of refueling outage after refueling complete.	B	4	Steam & Power (HB)	Heat Exchangers (Steam Generators)	N1.1.4

Table A1.15 1981 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1981)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
	1/1	4023	0	LER 80-014	Continuation of the 7/12/80 outage for steam generator tube repair.	B	4	Steam & Power (HB)	Heat Exchanger (Steam Generator)	N1.1.4
1)	6/18	7	18		Steam-feed flow mismatch caused a reactor trip.	A	3	Steam & Power (HB)	Instrumentation & Controls	D2.7
2)	6/19	19	6		The turbine was taken off line for testing.	B	1	Turbine Generators and Controls (HA)	Turbine	N1.1.4
3)	6/21	16	25		The unit was shut down when the #2 safeguard loads sequencer failed to test properly.	A	2	ESF Instrument (IB)	Instrumentation & Controls	N1.1.4
4)	6/29	17	85		Leak in "A" steam generator feedwater flow sensing line.	A	1	Condensate & Feedwater (HH)	Instrumentation & Controls	N1.1.4
5)	7/2	59	85		Reactor tripped due to false indication of high startup rate. Relay in intermediate range power monitor replaced.	A	3	Reactor Trip System (IA)	Relays	N2.1
6)	7/11	38	85		Leaking equalizing valve on the sensing line to a reactor coolant loop low flow transmitter caused scram. Valve and transmitter were replaced.	A	3	Reactor Vessel and Appurtenances (CB)	Valves	N2.1

Table A1.15 1981 Forced Shutdowns and Power Reductions for San Onofre 1

No.	Date (1981)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
7)	7/17	740	90	LER 81-017	Fire occurred due to lube oil leak in the #1 diesel generator.	A	1	Emergency Generator and Controls (EE)	Engines	N1.1.4
8)	8/20	0	90-60		Power reduction to repair salt water leak in condenser.	A	5	Main Condenser (HC)	Heat Exchangers (Condenser)	N1.1.4
9)	8/22	0	90-52		Power reduction due to low vacuum caused by vacuum pump seal water problem.	B	5	Main Condenser (HC)	Heat Exchangers (Condenser)	N1.1.4
10)	8/26	11	90		Manual shutdown to repair feedwater flow sensing line leak.	A	1	Condensate & Feedwater (HH)	Pipes, Fittings	N1.1.4
11)	9/3	1466	87	LER 81-20 LER 81-21	Voltage regulator failure required manual scram. Safety injection actuation occurred and two valves failed to open with design differential pressure. Values were redesigned and replaced.	A	2	Emergency Core Cooling (SFC) Electric Power (ED)	Valves	D1.2
12)	12/24	0	90-85		Power reduction to 372 Mw caused by inadequate vacuum resulting from insufficient steam to the air ejectors.	A	5	Steam & Power (HH)		N7.0

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Appendix A: San Onofre Unit No. 1

Part 2. Reportable Event Coding Sheets

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Table A2. 1 Coding Sheet for Reportable Events at San Onofre 1 - 1966

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
66-01	11057	000066	040066	A	CB	II		A	AS	G	C7	Steam generator was dropped during construction.

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Table A2. 2 Coding Sheet for Reportable Events at San Onofre 1 - 1967

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
67-01	23143	051967	012668	A	RB	J		GG	AG	C	N	A control rod drive mechanism jammed due to a broken latch pin.
67-02	31250	051867	061567	A	SA			C	AY	G	N	Containment integrity was broken by opening both airlock doors.
67-03	31250	050067	061567	A	HB	II		C	AY	H	N	Borated water was admitted to turbine side of steam generator during testing.
67-04		060267	071567	A	SFB	DD		C	ED	E	S1,S2	Both safety injection recirc pumps removed for repair after failing megger testing.
67-05	31251	062867	071567	B	HA	BB	I	B	BS,OD	H	N	Radwaste tank overflowed due to operator inattention.
67-06		070967	080067	B	RB	J	P	B	EP	D	N	Timer relay malfunction caused control rod drops.
67-07	63382	071767	080067	B	HA	HN		C	AD	C	N	Turbine blade damage during turbine overspeed test caused salt water leakage.
67-08		070067	080067	D	CB	DD		C	ED	D	N	Low megger readings on RCP's caused by wet nitrogen.
67-09	31253	091167	100967	B	CA	CC,OO		B	AU	D	N	Leaking pressurizer safety valve.
67-10	31254	100067	112067	B	HF	DD		B	HC,HD	D	N	Excessive vibration of main circulating pumps due to mussels in sea water intake lines.

Table A2. 2 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
67-11	31254	100067	112067	B	RB	J	K	B	EG	D	C7	False indication of control rod in core.
67-12	31254	100067	112067	B	AA	Z		B	AE	B	N	Reactor head ventilation duct collapsed.
67-13	31255	110167	121167	B	HF	OO	K	B	ED	D	C7	Closure of tsunami gate because of shorted limit switch caused a scram.
67-14	31255	110067	121167	B	MA	BB		B	BS,OD	H	N	Radioactive spills near coolant drain tank.
67-15	31256	121267	011568	B	RB	J		B	AS	E	C7	Five control rods dropped.
67-16	31256	120067	011568	B	RB	J	K	B	EF	D	C7	Control rod indicators were erratic.
67-17	31256	120067	011568	B	CB	II		B	HB	B	N	Steam generator "B" had a high delta T.

Table A2. 3 Coding Sheet for Reportable Events at San Onofre 1 - 1968

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
68-01		012068	020868	B	HF	N		B	HB	Z	N	Condenser flow blocked by debris.
68-02	31257	010068	020868	B	RB	J	K	B	EE	D	N	CR indicator light lit due to open circuit.
68-03	23360	020768	022668	B	EB	G		B	BY	B,E	S2,S3	Fire in cable tray.
68-04		020968	030068	B	HF	F		B	AG	D	C7	Intake stop gate accumulator reservoir tank ruptured.
68-05		030468	040068	B	RB	J		C	AL	D	C7	Control rod subgroup slipped into reactor.
68-06	31259	030968	040068	B	RB	J		B	BD	G	N	Miswired control rod drive.
68-07	24817	031268	040868	B	EB	G		B	BY	E	S2,S3	Fire in cable tray. Five month shutdown.
68-08		080068	090068	D	SFB	OO	B	C	AE	D	N	Faulty flow comparator failed to close LPCI valve.
68-09		090768	100068	D	RB	J		C	AS	D	C7	Two control rods dropped into core during tests.
68-10	42736	090968	120068	B	RB	J	F	B	AQ	D	N	Five control rods slipped causing scram.
68-11	42736	092268	120068	D	CB	DD		B	CA	D	N	During shutdown coolant pump rotated backwards.
68-12	42736	092668	120068	B	RB	J		B	AS	D	C7	Control rod group dropped due to clutch failure.
68-13		100168	110068	B	RB	J		B	AS	D	C7	CR subgroup 8 dropped.
68-14	29676	101468	112568	B	PC	E		B	HC	B	S1,S2	No flow in boron transfer pumps due to boron crystallization.

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Table A2. 4 Coding Sheet for Reportable Events at San Onofre 1 - 1969

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
69-01	34905	010769	020069	D	CA	OO,CC		A	AU	D	N	Leaking pressurizer spray valve.
69-02	34905	010969	020069	D	HA	NN		B	AU	D	N	Oil leak in turbine auto stop valve.
69-03		030569	040069	B	HF	P		B	AL	D	N	Traveling screen shear pin failure.
69-04		030569	040069	B	ED	S		B	EE	D	C7	Inverter failure on No. 1 vital bus.
69-05	38753	000069	070369	B	RB	J	K	B	EG	D	N	Excessive turbine load runback due to spurious signal from CE position indicator.
69-06	38751	000069	072269	B	SD	OO		C	AX	G	N	Leak in two containment isolation valves.
69-07	38750	000069	072269	B	SFB		C	C	EG	D	N	Partial failure of flow comparator of safety injection system.
69-08	39060	071569	102769	B	PC	DD		B	DV	B	S9	Boric acid pump plugged due to crystallization of boric acid.
69-09		081369	090069	B	IA		U	B	EF	D	N	RTD failure caused unit trip.
69-10		081369	090069	B	HH	OO		B	AY	D	N	FW control valve failed open due to air line failure.
69-11		081469	090069	B	RB	J	P	B	EF	D	N	Control rod dropped due to intermittent relay operation.
A069-06		100369	110069	B	BB	AA	N	B	EG	D	N	Stack gas monitor power supply failed.
A069-07		100669	110069	B	AA	E,HH		B	HB	D	N	Control rod shroud cooling fan belt failure.

Table A2. 4 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
A069-08	39059	100969	102469	B	HF	OO		B	AD	B	C7	Tsunami gate broke from attachment plate.
A069-09		101469	110069	B	SFB	QQ		C	EE	D	N	Safety injection recirc valve motor winding failed.
A069-10		102269	110069	B	RB		K	B	EF	D	C7	Grounded LVDT caused erratic CR position indication.
A069-11		102769	110069	B	ZZ				OF	Z	N	An earthquake was felt at San Onofre.
A069-12		102769	110069	B	PC	OO		B	AG	D	N	Vapor seal head tank fill valve failed open.
A069-13	42745	102869	021270	B	CA	OO		B	AU	C	N	Leaking root valves of pressurizer instrument column.
A069-14		102969	110069	B	HH	QQ		B	AD	D	N	Feedwater pump discharge valve motor operator fell off.
A069-15		112069	120069	B	ED	S		B	EE	D	C7	No. 3 inverter failed due to blown fuse.
A069-16		112969	120069	B	RB		K	B	EG	D	C7	Erroneous rod bottom indication given by failed bistable.
A069-17		112969	120069	B	RB		K	B	EG	D	C7	Erroneous rod bottom indication given by failed bistable.
A069-18		121069	010070	B	IA	S	I	B	EE	D	N	Pressurizer level indicator failed upscale due to blown fuse.
A069-19		121869	010070	B	ED	AA		B	EE	D	C7	Inverter for vital bus #2 failed.

Table A2. 5 Coding Sheet for Reportable Events at San Onofre 1 - 1970

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
A070-01		010770	020070	B	PC	DD		B	HB	D	N	North charging pump shaft broke.
A070-02		021670	030070	B	RB		K	B	EG	D	C7	Failed LVDT caused CR position indication.
A070-03		021770	030070	B	RB		K	B	EG	D	C7	Failed LVDT caused CR position indication.
A070-04		020570	030070	B	HB	HH		B	AU	D	C7	Steam generator tube leak.
A070-05		040870	040070	B	RB		K	B	EG	D	C7	Failed LVDT caused erroneous rod position indication.
A070-06		041370	040070	B	HB	QQ		C	AZ	D	N	Turbine control valves suddenly and spuriously changed positions.
A070-07	3200	052970	071070	B	HA	NN		B	BF	E	N	Turbine manually tripped due to over acceleration.
A070-08		052970	060070	B	RB		K	B	EG	D	C7	Failed LVDT caused erroneous rod position indication.
A070-09		072770	080070	B	IA		L	B	EG	D	N	A momentary spike occurred on a flux channel.
A070-10		082470	090070	B	SFC	F		C	BF	D	N	West safety injection recirculation pump breaker spuriously tripped.
A070-11		091270	100070	B	ZZ				BF	Z	N	A moderate earthquake was felt at San Onofre.
A070-12		091070	100070	B	PC	DD		B	HB	D	N	North charging pump shaft cracked.
A070-13	58006	101970	111670	B	SFC	OO		C	BB	D	N	A safety injection system isolation valve stuck open.

Table A2. 5 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
A070-14	58006	110470	111670	B	SFC	OO		C	AD,ED	D	N	Damaged safety injection system pump discharge valve.
A070-15		112170	120070	B	RB		K	B	EG	D	C7	Failed LVDT caused erroneous CR position indication.
A070-16		112770	120070	B	HH		U	B	EG	D	N	Failed thermocouple on the east FW pump gave an erroneous signal.
A070-17		120370	010071	B	ZZ					D	N	Contractors leased van damaged.
70-01	60821	000070	121570	D	CB	PD		C	AV	D	N	Cracked reactor coolant pump flywheel.

Table A2. 6 Coding Sheet for Reportable Events at San Onofre 1 - 1971

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
A071-01		020971	020071	B	ZZ				OF	Z	N	A moderate earthquake was felt at San Onofre.
A071-02		031871	030071	B	IA		M	B	EF	C	N	Cold soldered joints in a low pressure trip circuit caused scram.
A071-03		032371	030071	B	ED	S		B	BG	D	C7	No. 4 inverter failed due to a capacitor failure.
A071-04		041571	040071	B	IA		M	B	EH	D	N	A failed capacitor in a low pressure trip circuit caused a drift in the trip set point.
A071-05		042771	040071	B	CB	DD	U	B	EG	D	N	A RCP thermocouple gave an erroneous indication due to static charge of unknown origin.
A071-06		062271	060071	B	EA,HA			B	BG	D	S9	Loss of offsite power lines caused turbine overspeed.
A071-07		062671	060071	B	EB	J,S		B	EE	D	N	Fuse failure caused partial immobility of two CRD's.
A071-08		070771	070071	B	HA	QQ		C	ED	D	N	Turbine load limit valve motor failed during a test.
A071-09		072171	070071	B	HA	T		A	EC	G	N	Gradual decay of generator excitation because maintenance took too long.
A071-10		072171	070071	B	HA	NN		C	BW	D	S9	Generator out-of-step condition caused turbine overspeed.
A071-11		083171	080071	B	ZZ				OF	Z	N	A small earthquake was recorded at San Onofre.

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Table A2. 6 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
A071-12		092171	090071	B	IA		M	B	EH	D	N	A zener diode failure in a low pressure trip circuit caused a drift in the trip set point.
A071-13		092371	090071	B	RB	J,S		B	EE	D	N	Fuse failure caused partial immobility of two CRD's.
A071-14		093071	090071	B	ZZ				OF	Z	N	A small earthquake was recorded at San Onofre.
A071-15		110971	110071	B	SHC	DD		C	OC	A	N	AFW pump tests were scheduled monthly instead of bi-weekly.
A071-16		111371	110071	B	IA		M	B	EH	G	N	A bad soldered joint in a low pressure trip circuit caused a drift in the trip set point.
A071-17	55346	122671	022572	D	HB	OO		C	BA	D	N	Two steam relief valves failed to open on test.

Table A2. 7 Coding Sheet for Reportable Events at San Onofre 1 - 1972

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
A072-01		010072	012872	C	EE	QQ		C	BB	D	N	DG fuel line isolation valve failed to close.
A072-02	69325	010072	012872	C	SD	OO,QQ		C	AG,AE	D	N	An isolation valve failed to close.
A072-03	55249	010072	021172	C	RC	R		C	BI	H	N	Cladding failure occurred in two fuel rods.
A072-04		021272	020072	C	PC	QQ		C	ED	D	N	Seal water filter bypass valve failed open during a test due to a shorted valve operator.
A072-05		020272	020072	C	CB	HH		B	AU	D	C7	Steam generator tube leaked.
A072-06		040772	040072	B	HA	QQ		C	BF	D	N	Turbine control valve spuriously changed positions.
A072-07	71397	043072	050972	B	HH	QQ		B	AB	D	S9	Excessive feedwater flow due to a regulating valve failure.
A072-08	84464	050272	050072	B	HA	OO,QQ	P	B	AG,AZ	D	N	Two turbine control valves in the main steam system failed.
A072-09		060572	060072	B	IA	L		B	OJ	H	N	Operator bumped into a flux monitor causing a unit runback.
72-01	78514	070872	021573	B	CB	II		B	AU	D	C7	Steam generator C tubes leaked.
72-02	78514	071872	021573	B	EE	N		C	HE	D	N	Diesel generator had broken wire in the exciter field.
72-03	74190	072972	082872	B	HA	HH,T		B	BF,EE	D	S9	Turbine overspeed when unit tripped due to loss of generator load.

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Table A2. 7 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
72-04	78514	091272	021573	B	CB	II		B	AU	D	C7	Steam generator C tubes leaked.
72-05	78514	091272	021573	B	CB	II		B	AU	D	C7	Steam generator A tubes leaked.
72-06	78514	092072	021573	D	RB	J		C	AS	D	C7	Four control rods slipped.
72-07	78514	120972	021573	B	ED	AA		B	ZZ	D	C7	Inverter on vital bus No. 3 failed.

Table A2. 8 Coding Sheet for Reportable Events at San Onofre 1 - 1973

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
SI73-01		010573	082873	B	CB	II		B	AU	D	C7	Steam generator A tubes leaked.
SI73-02		011073	082873	B	ED	AA	I	B	EE	H	C7	Operator inadvertently bumped a switch deenergizing the inverter to vital bus No. 4.
SI73-03	79373	021373	030873	B	EE	N	U	C	HB,BL	D	N	Overheating of diesel generator No. 2 due to stuck cooling water thermostats.
SI73-04	79468	021673	031273	B	EE	N		C	AD	D	N	Failure of fuel injection pump for diesel generator no. 1.
SI73-05		022073	082873	B	RB	J	T	B	AY	D	C7	A switch spuriously opened in the CRD positioner and a CR slipped into the core.
SI73-06		022173	030873	B	ZZ				OF	Z	N	A moderate earthquake was felt at San Onofre.
SI73-07		050873	082873	B	EE	P		B	AQ	D	N	Diesel generator failed because of a clogged filter in the air start mechanism.
SI73-08	81591	060773	070673	D	EA,EE	LL,N		B	ED	D	S1,S2	Loss of offsite power due to tranrformer trip. Also one diesel generator failed.
SI73-09		071473	022574	D	ZZ				OF	Z	N	A small earthquake was sensed at San Onofre.
SI73-10		080673	022574	B	ZZ				OF	Z	N	A small earthquake was sensed at San Onofre.
SI73-11		081773	070673	B	ED	AA		B	EE	D	C7	Inverter No. 2 failed.

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Table A2. 8 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
SI73-12	87066	101673	112073	B	ED	N		C	AB	E	N	Failure of fuel pump for diesel generator.
SI73-13	87016	102173	102273	B	HH,SFC	OO,QQ		B	HA,HH	H	S9	During power reduction, unit tripped due to excessive FW flow. SIS actuated. Motor operator of SI valve was damaged by water hammer.
SI73-14		102873	022574	D	ZZ				OF	Z	N	A small earthquake was felt at San Onofre.
SI73-15		112973	022574	D	EA	F		B	EE	D	N	Electrical disturbance in offsite grid.
SI73-16		121873	011474	D	SD	OO		C	AW	D	N	Containment isolation valve failed leaky.

Table A2. 9 Coding Sheet for Reportable Events at San Onofre 1 - 1974

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
SI74-01		011474	020874	D	HB	Z,KK		B	AD	D	N	Main steam line knee support found misplaced.
SI74-02		022474	081474	B	IA		H	B	EH	D	N	Loop B low pressure trip set point high.
SI74-03		040374	081474	B	PC	OO		B	HL	D	N	Boron crystallization prevented operation of BAT discharge valve.
SI74-04		061174	081474	B	IA		L	B	EG	D	N	Spurious high flux indication caused turbine runback.
SI74-05		061474	081474	B	ED	AA	P	B	ED	D	C7	No. 1 inverter failed due to shorted SCR.
SI74-06	94768	070774	071574	D	WB	U	L	B	AU	B	S2	Leaking cooling coils flooded detector thimbles, causing a reactor trip.
SI74-07		070974	021275	B	HH	PP		B	AL	D	N	FW check valve to steam generator C failed.
SI74-08		042574	081475	B	CB	II		B	AU	D	C7	Tube leak in steam generators "A" and "C".
SI74-09		072474	021275	B	ZZ					Z	N	FBI reported a sabotage threat.
SI74-10	95378	081374	093074	B	EE	N,DD		C	AG	D	N	Diesel generator cooling pump seized.
SI74-11		082074	021275	B	IA		I	B	EG	D	N	Spurious trip from pressurizer level indicator.
SI74-12		102174	021275	B	RB	J		B	AS	D	C7	Subgroup 8 control rods dropped into the core.

Table A2.10 Coding Sheet for Reportable Events at San Onofre 1 - 1975

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
SI75-01		011375	082075	B	IA		C,M	B	EH	D	N	Low pressure trip setpoint drift.
SI75-02	93568	011475	012275	B	EE	N		C	AO	D	N	Diesel generator failed due to separation of pulley from drive shaft.
SI75-03		021275	082075	B	HF		U	B	EG	D	N	Circulating water delta T monitor failed.
SI75-04	100574	021275	031275	B	EE	N,DD		C	HB	B	N	Diesel generator failed due to insufficient flow of fuel transfer pump.
SI75-05		021975	082075	B	ED	AA		B	BG	D	C7	No. 2 inverter failed, tripping the reactor.
SI75-06		022875	033175	B	SFB	OO		B	OK	B	S9	Potential safety injection failure due to single valve failure.
SI75-07		031575	061675	C	SD	OO		C	BB	D	N	Leakage of containment isolation valve.
SI75-08		040275	082075	C	FD	L		B	AL	D	N	Fuel transfer system was damaged.
SI75-09		042275	082075	C	ED	AA		B	BG	D	C7	No. 2 inverter failed, tripping the reactor.
SI75-10		042575	082575	B	IA		L	B	EH	D	N	Overpower trip set point drifted.
SI75-11		041375	082575	C	CB	II		C	AU	D	C7	Steam generator A tubes leaked.
SI75-12		041875	082575	B	EA	F		C	BG	H	N	Operator deenergized two 4 kv buses during a trip.
SI75-13		052175	082575	B	HF	P		B	AQ	Z	N	Heavy influx of seagrass clogged the traveling screens.

Table A2.10 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
SI75-14	104065	061975	070775	B	BA,BB		N	B	OC	H	N	Air and drinking water samples not taken.
SI75-15		061175	082575	B	CB	II		B	AU	D	C7	Steam generator C tube leaked.
SI75-16		070975	000075	B	HF		T	B	BB	D	N	Chlorination microswitch failed to discontinue chlorination.
SI75-17	106454	081275	091275	B	EE	N,U		B	AR	D	S1	Diesel generator #1 overheats due to blocked cooling.
SI75-18	106455	081375	091275	B	EE	N,FF		B	AW	B	S1	Diesel generator #2 overheats due to loss of cooling water.
SI75-19		082075	000075	B	PC	DD		C	AG	D	N	South boric acid transfer pump bearing seized.
SI75-20		082075	000075	B	RB	J	C	B	BC	D	C7	Control rod group 3 skipped steps.
SI75-22		101975	000075	B	ED	AA	C	B	BY	D	C7	Oil filled capacitor in the No. 3 inverter failed.
SI75-23		000075		B	HH	Z		B	AL	D	N	FW flow straightening device became loose.
SI75-24	108558	001175	112575	B	BB		N	B	OC	H	N	Offsite particulate filters not collected for two weeeks.

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Table A2.11 Coding Sheet for Reportable Events at San Onofre 1 - 1976

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER76-01	114077	C32276	032376	B	FB	O		B	AO	C	N	Crack in shipping cask lifting device.
LER76-02		050376	022577	B	FB	O		B	AO	C	N	Crack in shipping cask lifting device.
LER76-03	115452	052076	061876	B	HB	II,OO	E	B	AU	D	N	Leak in instrument valve caused low steam generator flow indication.
LER76-04	115878	062876	071476	B	CB		E	B	EG	D	N	Loop C flow transmitter failure caused spurious trip.
LER76-05		060176	072676	B	ID	AA	L	B	ED	D	N	Axial monitoring system failed due to shorted power supply.
LER76-06	117666	073076	082576	B	CB	II		B	AU	D	C7	Steam generator tube failed.
LER76-07	117154	073176	082576	D	PC	DD		C	HC	B	C4	Boric acid transfer line was blocked by boron crystallization
LER76-08	118184	082376	091676	B	ED	AA		B	EE	D	C7	Inverter No. 1 failed causing loss of feedwater control.
LER76-09	119784	000076	111676	C	RA	KK		C	AI,HD	B	N	Thermal shield flexure supports failed.
LER76-10	119783	000076	091576	C	RA	KK		C	AI,HD	B	N	Steam generator tubes had defects.
LER76-11	120269	000076	120176	C	CB	II,KK		C	AB	D	C7	Steam generator antivibration bars were worn.
SI76-01		010176	022577	B	ZZ				OF	Z	N	A small earthquake was sensed at San Onofre.

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Table A2.11 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
SI76-02		210176	022577	B	EA	G		B	BG	Z	S1	Loss of offsite power due to brush fire.
SI76-03		220976	022577	B	IB		I	C	EG	D	N	Spurious pressurizer high level signal tripped reactor.
SI76-04		220976	022577	B	ED	AA	C	B	BY	D	C7	Oil-filled capacitor in the No. 2 inverter failed.
SI76-05		221776	022577	B	ED	AA		B	BG	D	C7	No. 4 inverter failed tripping reactor.
SI76-06		030576	022577	B	FB	JJ		B	OD	H	N	Contamination was spread from spent fuel cask area.
SI76-07		032776	022577	B	FB	JJ		B	OC	H	N	Spent fuel cask shipped without knowledge of amount inside.
SI76-09		041776	022577	B	HA		C	B	BF	G	N	Turbine tripped due to low overspeed setting.
SI76-11		041776	022577	B	HH	D,DD		B	BF	D	N	FW pump vibration caused high bearing temperature.
SI76-12		041976	022577	B	HH	PP		B	AL	D	N	FW check valve seat became disconnected.
SI76-15		070276	022577	B	FB	JJ		B	AX	D	N	Shipping cask neutron shield leaked borated glycol.
SI76-16		072676	072577	B	EB	G		B	BY	E	N	Brief construction fire scorched electric cable jackets.
SI76-21		082376	022577	B	ID	AA	K	B	EG	D	C7	Rod bottom indicator power supply failed causing runback.

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Table A2.11 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
SI76-23		092576	022577	B	ED	AA	C	B	BY	D	C7	Oil-filled capacitor in the No. 3 inverter failed.
S176-24		092576	022577	B	ED	AA		B	BG	D	C7	No. 2 inverter failed.
S176-25		092576	022577	B	ED	AA	C	B	BY	D	C7	Oil-filled capacitor in the No. 3 inverter failed.
SI76-26		101876	022577	B	ZZ				OF	Z	N	A moderate earthquake was felt at San Onofre
76-1	111601	000076	030176	B	IF		U	B	EG	D	N	Offshore temperature sensors failed.
76-2	115877	000076	062876	B	EE	KK		B	AV	E	N	Voids found in diesel generator building wall.
76-3	115878	000076	071576	B	IF		U	B	EG	I	N	Offshore temperature sensors failed due to rough seas.

Table A2.12 Coding Sheet for Reportable Events at San Onofre 1 - 1977

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER77-01	122203	011777	020477	D	BB			B	OC	A	N	Airborne samples not collected.
LER77-02	122204	011777	020777	D	SHB	Z		C	AR	C	N	Corrosion in containment spray piping.
LER77-03	122132	012477	021877	D	WB	Z,DD		A	AU	A	N	Leak in RHR pump cooling water line due to line being cut into.
LER77-04	122133	021577	030277	D	SHB	Z		C	AO	E	N	Two leaks found in containment spray system.
LER77-05	123082	022077	030477	D	SA			C	AX	G	N	Leak in containment vessel due to drilled holes.
LER77-10	125174	041777	051377	B	CB	OO		B	AU	D	N	Reactor coolant system leak through valve packing.
77-01	124898	042177	051177	B	IF		U	C	AL	D	N	Offshore temperature sensor found to be missing.
LER77-06	125175	042677	052577	B	FC	DD		B	HC	D	C4	Failure of boric acid transfer pump due to boron precipitation.
LER77-07	125181	051077	052577	B	EE	N,KK		C	AL	E	N	Fuel oil bypass line supports omitted on diesel generators.
77-02	126491	060177	062977	B	IF		U	C	AL	D	N	Offshore temperature sensor found to be missing.
77-03		061677	071277	B	FB	OO		B	AY	D	N	Spent fuel shipping cask drain valve found open.
LER77-08	125703	061477	070177	B	ED	QQ,S		B	BB	D	C7	Inverter deenergized by fuse failure.

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Table A2.12 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER77-09	129554	072977	082577	B	CA	CC		B	OK	B	N	Pressurizer heat-up rate nonconservative.
77-04	127978	073077	081877	C	FB	OO		B	AY	H	N	Spent fuel shipping cask drain valve found open.
LER77-12	128944	080977	090877	B	SA	PF		B	OC	C	N	Deficiency found in electrical penetration documentation.
LER77-11	128890	082477	090777	B	SFC	DD		B	BH	B	N	Charging pump circuitry change fails to eliminate single failure effect.
LER77-13	129778	091977	100377	D	CB	II,KK		C	AB	D	C7	Tube wall thinning due to anti-vibrational bars.
LER77-14	130702	100177	101477	D	CB	II,KK		A	BV,AU	D	C7	Inadvertent dilution of reactor coolant due to steam generator leak.

Table A2.13 Coding Sheet for Reportable Events at San Onofre 1 - 1978

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER78-01	135753	011678	021078	B	HF	DD,F	P	B	BF	D	N	Saltwater cooling pump breaker trips open when other pump is down for maintenance.
LER78-02	136374	013078	022378	B	SHB	OO		C	BB	D	N	Containment spray valve fails to close in testing.
LER78-03	137341	031578	032878	B	SHB		C	B	BF	D	N	Two containment spray actuation system inverters tripped.
LER78-04	138234	032878	042578	B	EE	N		C	AG	D	N	Diesel generator fails to start due to lack of lubrication.
LER78-05	138253	041878	051078	D	SFC	OO		C	AE,AS	D	N	Safety injection valve opens slowly due to distorted valve shaft.
LER78-06	138254	042678	051978	B	SFC			B	HB	B	N	Reanalysis of small break LOCA indicated lower than anticipated flow.
LER78-07	139587	060778	062978	B	ED	S	C	B	BF	D	C7	Input fuse to inverter fails.
LER78-08	140322	071878	080978	B	EE	N		C	AG	D	N	Diesel generator fails to start due to binding of linkage.
LER78-09	140321	080178	080978	B	HH		E	B	AL	D	N	Flow straightener became dislodged and lodged against feedwater flow orifice plate.
LER78-10	140353	081878	091478	B	HH,SFC	OO		B	BH	G	N	Feedwater pump safety injection valve inadvertently opened.
LER78-11	141389	102378	110678	C	HH	GG		C	HH,AH	D	N	Shock absorbers found inoperable.

Table A2.13 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER78-12	141196	102378	112178	C	SPC	Z		C	AR	D	N	Leaks found in charging pump discharge line.
LER78-13	142839	112578	122078	B	HH		E	B	AL	D	F	Flow straightener dislodged.
LER78-14	145212	120578	010379	B	SHB	00		A	AY	H	N	Hydrazine additive pump recirc valve left open.
78-01		091378	101378	B	HF	P		B	AQ	I	N	Large quantity of fish impinged on intake screens during storms.
78-02		091878	101878		MC	P		B	AL	Z	N	Settling plates damaged by increased marine activity.
78-03		063078	101378	B	MC		U	B	EG	D	N	Two temperature sensors failed.
78-04		101078	121978	B	MC		U	B	EG	D	N	Two temperature sensors failed.

Table A2.14 Coding Sheet for Reportable Events at San Onofre 1 - 1979

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER79-01	147264	010979	020779	B	SD	QQ		C	BB	D	N	Containment air unit cooling water valve failed to close.
LER79-02	150075	040479	050479	B	HH		E	B	AL	D	N	Flow straightener dislodged.
LER79-03	149445	040479	050379	B	SD	OO		C	BB	D	N	Containment air unit cooling water valve failed to close.
LER79-04	151481	010979	041979	B	DB		N	B	OK	A	N	Loss of benthic survey data not reported.
LER79-05	151480	040279	042779	B	IF		U	B	AG	D	N	Sea temperature data lost due to instrument malfunction.
LER79-06	149247	041379	051179	B	BB		N	B	ASL	D	N	Four environmental radiation dosimeters lost due to vandalism.
LER79-07	150036	042379	052279	B	HB		E	B	EG	D	N	Steam flow indicator failed.
LER79-08	150253	060479	061879	D	CB	II		C	AU	D	C7	Leaking steam generator tubes.
LER79-09	150252	060579	061979	D	HH	GG		C	HH,AH	D	N	Feedwater line shock absorber fails.
LER79-10	152656	060579	061579	D	HB	II		C	AO	E	N	Cracks in steam generator feedwater nozzle to reducer welds.
LER79-11	151831	080679	083179	B	DB		N	B	OC	A	N	Drinking water sample lost.
LER79-12	151834	080579	083079	B	HF			B	OC	A	N	Fish impingement data not collected.
LER79-13	152654	090679	091179	B	SHB	Z		C	AO	D	N	Cracks in suction piping from containment spray pumps.

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Table A2.14 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER79-14	152206	082979	092879	B	EC		R	C	EE	D	N	15 VDC power supply failed disabling one diesel generator and one safety injection train.
LER79-15	154812	092579	100979	B	SD	FF		A	AH	H	N	Containment personnel air lock left open for 10 seconds.
LER79-16	154815	091579	100579	D	SPC	Z		C	AO,A	D	N	Crack-like indication in safety injection line weld.
LER79-17	153395	110779	112179	B	EB			T	BF,ED	D	C7	Short circuit in 480V bus due to rodent.
LER79-18	153387	110979	112679	D	MA	KK,FF		C	AL	E	N	Pipe support missing.
LER79-19	153668	111679	113079	B	EE	KK		C	AL	E	N	Pipe supports missing.
LER79-20	153669	112679	120779	D	WB	KK		C	AL	E	N	Pipe supports missing.
LER79-21	153670	111479	121279	B	EC		P	B	BF	D	N	Load sequencer power supply trips off.
LER79-22	153819	113079	121779	D	WB	KK		C	AL	E	N	Pipe supports missing
LER79-23	153873	101079	121179	B	CB,IA	CC	M	C	EI	H	N	Low pressure trip safety setting too low on one pressure channel.
LER79-24	153936	120379	013180	B	HH		E,I	B	OK	H	N	Modifications made to equipment without approved design change.
LER79-25	153496	101179	011180	B	CB,IA		F,U	B	EG	D	N	T-AVG converter fails.
LER79-26	153937	122679	011080	B	SHC	DD,D		C	AB,AK	H	N	Steam driven aux feedwater pump bearing fails.

Table A2.15 Coding Sheet for Reportable Events at San Onofre 1 - 1980

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER80-01	154456	011080	012580	B	HF	Z,KK		C	BC	E	N	Piping supports fail to meet seismic criteria.
LER80-02	154455	011680	012880	B	HH	OO	P	B	BF	G	S9	Construction worker bumped a relay tripping a FW pump.
LER80-03	154623	010980	020580	B	SD,PA	QQ,HH		B	BB	D	C8	Service water containment isolation valve fails to close due to clogged air line.
LER80-04	154623	010980	020580	B	SD,PA	QQ,HH		B	BB	D	C8	Service water containment isolation valve fails to close due to clogged air line.
LER80-05	155571	021880	022980	B	RF	H		B	HB	I	N	Condenser cooling water flow partially blocked by seaweed due to severe weather.
LER80-06	155475	031080	032480	B	HF	DD		B	HC	D	S1,S3	Loss of all salt water cooling flow to plant.
LER80-07	155983	022480	032080	B	SFC	Z		B	HE	D	N	Crack found in charging pump discharge line, due to cavitation.
LER80-08	156134	031880	040980	B	HF	KK		A	HD,AR	D	N	Saltwater cooling system pipe supports fail.
LER80-09	155441	033180	040280	B	BB		N	B	OC	I	N	Benthic data not taken when required due to severe weather.
LER80-10	156333	031880	040980	B	SFC	DD,D		B	AB	D	N	Charging pump thrust bearing fails.
LER80-11	156334	031080	040880	B	PC	CC		B	AD	H	N	Pressurizer relief tank rupture disk ruptures due to overfilling.

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Table A2.15 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER80-12	156205	032480	042180	B	EE	N,DD		B	BF	D	N	Diesel generator fuel oil transfer pumps fail due to water flooding due to failure of sump pumps.
LER80-13	157052	032980	042880	B	SG	S		B	AM	G	N	Control room emergency air treatment system dampers fail closed due to wrong fuse.
LER80-14	166740	041480	072280	C	CB	II		C	AU	D	C7	9 steam generator tubes found to be leaking.
LER80-15	158278	042280	050580	D	EA		P	A	DF	G	S7	4 kV and 480 V onsite and offsite power lost.
LER80-16	156982	042080	052080	C	IE	FF	S	B	EG	D	S1,S2	Source range nuclear instrumentation fails during refueling due to seal leakage.
LER80-17	156956	050580	051480	C	FD	PP		B	AU	D	N	Erroneous boron results from reactor refueling cavity due to contamination of chemistry sample.
LER80-18	156925	050680	051680	C	IE		F	A	AE	B	N	Incore flux thimble bent.
LER80-19	158666	051080	052280	D	CF	KK		C	AL	E	N	Pipe support found to be missing.
LER80-20	158570	051380	052880	D	HH,HB	GG		C	AM	H	N	Failed hydraulic snubbers found.
LER80-21	158571	051580	052980	D	HH	KK		C	HD,HH	D	N	Feedwater pipe supports found to have failed.
LER80-22	156924	050780	052080	D	CB	E		C	AV	C	N	Pinhole found in reactor coolant pump seal injection pipe.

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NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER80-23	157678	052380	061880	D	WB	U		A	AO	G	N	Flaw found in component cooling water heat exchanger weld.
LER80-24	158572	051680	052980	D	HB	Z		C	AO	E	N	Indications found in main steam piping welds during radiographic examination.
LER80-25	158621	050580	060680	D	CB	DD		C	AO	C	N	Linear indications found in reactor coolant pump flywheel bores during dye penetrant examination.
LER80-26	158275	060980	061080	D	SA,HB	Z		C	AD	B	N	Steam line break analysis fails to consider peak containment pressure.
LER80-27	160255	052880	062380	D	HH	Z		C	AO	E	N	Faulty welds found in feedwater piping.
LER80-28	160254	061280	063080	D	SFC	KK		C	AM	E	N	Inadequate pipe guides found on safety injection system injection lines.
LER80-29	158289	070580	072180	D	CB	II,FF		A	AU	D	C7	Reactor coolant system diluted due to leakage of inflatable plugs used to isolate steam generators.
LER80-30	158778	040480	072380	B	IF		U	B	AG	D	N	Ocean thermal monitoring data not taken due to motor failure.
LER80-31	159580	072880	082180	D	HF	QQ		B	AM	G	N	Saltwater cooling pump discharge valve fails to open due to wrong spring installed.
LER80-32	160238	071780	081880	D	PA,WA	QQ		B	BB	B	N	Containment isolation valve in service water system failed to close due to desiccant contamination of instrument air.

Table A2.15 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER80-33	160315	090280	091680	D	IB		P	C	EG	B	N	Sequencer relays fail to reset SIS properly during test.
LER80-34	160322	090180	091780	D	CB	II		A	AU	G	C7	Reactor coolant dilution due to steam generator leak.
LER80-35	160510	091580	101080	D	ID		T	C	ED	B	N	Containment isolation panel reset switches found defective.
LER80-36	160162	092280	100380	D	CB	II		A	AU	D	C7	Reactor coolant dilution due to seal failure during steam generator decontamination.
LER80-37	160875	111379	102780	B	IF		U	B	AG	D	N	Ocean thermal monitoring data not taken due to motor failure.
LER80-38	161910	112280	120980	D	EB	F		B	AY	H	S7	AC power to all station auxiliaries lost due to operator opening wrong breaker.
LER80-39	162578	101280	122380	D	EE	E		C	AK	B	N	Diesel generator turbocharger thrust bearings worn due to inadequate lubrication.

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Table A2.16 Coding Sheet for Reportable Events at San Onofre 1 - 1981

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER81-01	163843	011681	011981	C	SFC		C,P	B	EF	B	C4	Design review indicated that loss of power during safety injection sequencing would cause SIS loads to not load.
LER81-02	164271	020281	021781	D	HH	O,Z		C	AL	E	N	Bolts required for seismic qualification of a feedwater line were missing.
LER81-03	166464	041781	060381	C	SFB	KK		C	AG	D	C2	Two mechanical snubbers for the safety injection system were found inoperable.
LER81-04	166143	041681	050481	D	SFB	QQ			AC	A	N	Safety injection recirc valves were not qualified for necessary environment.
LER81-05	166391	033181	051181	B	BA				OC	A	N	Personnel failed to conduct semi-annual crop monitoring required by ETS.
LER81-07	166668	051581	060181	D	CF	DD				B	C4	RHR pump couplings were replaced due to failure of similar items under test.
LER81-06	166646	042881	051881	D	IB	G			AN,OA	B	C4	Safety-related circuits with terminal blocks in containment require replacement.
LER81-08	166734	052481	062381	D	HB	II		A	AE,AV	D	N	Damage to steam generator thermal sleeve, cracks in feedring and debris found in SG feed nozzle.

Table A2.16 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER81-09	166736	060981	060981	D	WB	U,OO		A	HB,AG	D	N	Component cooling water heat exchanger and valve blocked by barnacle growth.
LER81-10	166738	060381	062581	D	SA			B	AY	D	N	During shutdown both airlock doors were twice opened simultaneously due to damaged mechanism.
LER81-11	171971	051081	070281	C	AD	Z		B	AU,OD	D	C3	Beach sand found contaminated by inadvertent leakage through a non-radioactive drain line.
LER81-12	167722	062381	072281	B	IA		H	B	EI	A	N	Low pressure trip setpoints were nonconservative due to a procedural error.
LER81-13	167705	061881	072781	B	CJ	OC		B	AY	H	N	PORV open briefly twice during normal pressure transient due to controller being turned off.
LER81-14	167853	063081	072781	B	IA		E	B	EG	D	C2	Failure of two flow sensors allows power operation greater than indicated power level.
LER81-15	167849	063081	072281	B	EE	N		B	EF,BT	G	N	Diesel generator tripped due to lube oil leaking from a drain valve left open.
LER81-16	168175	071181	072481	D	SA			B	AY	D	N	Both personnel airlock doors were open simultaneously, due to damaged latching mechanism.

Table A2.16 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER81-17	168076	071481	061281	B	EE	N,Z		C	AW,BY	D	N	Fire occurs in diesel generator building due to fatigue failure of a lube oil line.
LER81-18	168122	071781	073181	D	MB	JJ		B	AW,OG	A	N	Excessive oxygen in the waste gas tank ignited causing tank damage.
LER81-19	169081	081681	091181	B	PC			B	AW,AO	D	N	On two occasions, excessive leakage occurred on a charging pump seal water line.
LER81-20	166829	090381	091481	B	SFB	OO		B	BA	B	S2,S7	Design error causes failure of two valves resulting in failure of both trains of SIS.
LER81-21	168830	090381	091481	B	EB	AA		B	ED	D	C6	Voltage regulator failure caused erratic feedwater control and resulted in safety injection actuation.
LER81-22	196629	100381	102081	D	CC	GG,EF		C	BT	D	N	Seal leak causes loss of hydraulic fluid in main steam system snubber.
LER81-23	171001	092581	111681	D	SHB	AA		B	DG	D	N	Loss of CSAS power supplies caused inadvertent containment spray actuation.
LER81-24	170071	102581	110381	D	SD	QQ		C	BB	C	C4	Three manually operated isolation valves failed to close initially when actuated.
LER81-25	170073	102581	110381	D	SD	QQ		C	BB	D	N	On different dates, two air operated isolation valves failed to close.

Table A2.16 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER81-26	171051	110281	116681	D	SFC	QQ		C	BB	E	C4	Valve failure caused diversion of SI flow to the condensor.
LER81-27	171103	110981	112381	B	SFC				BV	A	N	Procedural deficiency results in adequate boron concentration in RWST.
LER82-28	171048	103081	111381	D	SFC		R	C	EG	B	C4	Safeguards load sequencer failed to operate due to design error causing LOOP.
LER81-29	171700	111981	121781	B	EE	N		C	BD	G	N	Diesel generator failed to start due to low oil level in governor after maintenance.
LER81-30	171818	111581	121481	D	BB	P	N	A	EG,BC	G	N	Two weekly air samples were invalid due to misalignment of filters by personnel.
LER82-03	172476	121281	030582	D	RB	I		B	AD,AO	D	N	Control rod weld failure causes one or two rodlets to remain in the core.
LER82-06	172604	112081	030282	B	SHB	OO		C	AU	D	N	During maintenance of refueling water pumps water was inadvertently sprayed into containment.
LER82-13	175125	100281	060182	D	MA			OC,OH		A	N	Midpoint and end point monitoring were omitted during a planned liquid release.

APPENDIX G

NRC STAFF CONTRIBUTORS AND CONSULTANTS

This Safety Evaluation Report is a product of the NRC staff and its consultants. The NRC staff members listed below were principal contributors to this report. A list of consultants follows the list of staff members.

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		VI-7.C.1	October 1980
		VIII-3.B	January 1981
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		V-11.B	December 1980
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		VII-1.A	August 1981
		VII-2	August 1981
B. Shindell	EG&G, Idaho	VIII-2	June 1980
A. Udy	EG&G, Idaho	VI-4	November 1980
		VI-7.A.3	October 1981
		VIII-4	November 1981
D. Weber	EG&G, Idaho	III-1	October 1981
		VII-3	October 1981
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D. Barrett	Franklin Research Center	III-2	September 1982
A. Gonzales	Franklin Research Center	III-7.B	August 1982
T. Stilwell	Franklin Research Center	IX-5	August 1982
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* No longer with the Nuclear Regulatory Commission.

Name	Company	Topic	Report Date
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T. Nelson	Lawrence Livermore National Laboratory	III-6	May 1982
J. Selan	Lawrence Livermore National Laboratory	VIII-1.A VIII-1.A	January 1982 May 1982
W. Stein	Lawrence Livermore National Laboratory		
D. Vreeland	Lawrence Livermore National Laboratory	VI-2.D	October 1981
A. Crawford	Oak Ridge National Laboratory	Operating Experience	July 1983
G. Mays	Oak Ridge National Laboratory	Operating Experience	July 1983
J. McDonald	Texas Tech University	II-2.A	May 1980
G. Overbeck	Westec	V-10.B	June 1981
J. Scherrer	Westec	II-3.A II-3.B II-3.B.1 II-3.C	September 1982 September 1982 September 1982 September 1982

APPENDIX H

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS COMMENTS ON DRAFT NUREG-0829 AND STAFF RESPONSE

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

August 13, 1985

Honorable Nunzio J. Palladino
Chairman
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Dr. Palladino:

SUBJECT: ACRS REPORT ON THE SYSTEMATIC EVALUATION PROGRAM REVIEW OF THE SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 1

During its 304th meeting, August 8-10, 1985, the Advisory Committee on Reactor Safeguards reviewed the results of Phase II of the Systematic Evaluation Program (SEP) as it has been applied to the San Onofre Nuclear Generating Station, Unit 1. These matters were discussed also during subcommittee meetings in Washington, D. C. on November 27, 1984 and June 19, 1985. During our review, we had the benefit of discussions with representatives of the Southern California Edison Company (Licensee) and the NRC Staff. We also had the benefit of the documents referenced.

The San Onofre plant is the last to be reviewed under the SEP. The plant is in Group 2 of the SEP, which includes the five oldest plants still in operation. Construction began in 1964, and the plant has been in commercial operation since 1968 under a Provisional Operating License. The San Onofre plant utilizes a 3-loop Westinghouse reactor. It has an electrical capacity of about 430 megawatts.

In our report dated May 11, 1982 on the SEP evaluation of the Palisades Plant, we commented on the objectives of the SEP and the extent to which they had been achieved. Our review of the SEP in relation to the San Onofre plant has led to no changes in our previous findings regarding the extent to which the objectives of the SEP have been achieved and the manner in which the NRC Staff has conducted its review and assessment.

Of the 137 topics to be addressed in Phase II of the SEP, 24 were not applicable to the San Onofre plant and an additional 24 were deleted because they were being reviewed generically under either the Unresolved Safety Issues Program or the Three Mile Island Action Plan. Of the 89 remaining topics addressed in the NRC Staff's review, 53 were found to meet current NRC criteria or to be acceptable on another defined basis. We have reviewed the assessments and conclusions of the NRC Staff relating to these topics and have found them appropriate.

The 36 remaining topics involved 86 issues relating to areas in which the San Onofre plant did not meet current criteria. These issues were

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addressed by the Integrated Plant Safety Assessment Report (IPSAR) and various resolutions have been proposed.

For 41 of the issues included in the Integrated Assessment, the NRC Staff has concluded that no backfit is required. We concur.

For 12 issues, resolution has been achieved by changes to the Technical Specifications or to procedures. We find these acceptable.

For 5 issues, relating to 3 topics, resolution required backfits involving plant systems or components. The structural or hardware backfits resulting from the Seismic Upgrade Program are not included in this number.

As has been the case for the other plants in the SEP, the Integrated Assessment had not been completed for a number of issues at the time the IPSAR was published; in this case, 28 issues relating to 13 topics. For each of these, the Licensee has agreed to provide the results of studies, analyses, and evaluations that are needed by the NRC Staff for its assessments and decisions. All of these issues are of such a nature that hardware backfits may be required for their resolution. The resolution of these issues will be addressed by the NRC Staff in a supplemental report.

One outstanding issue relates to the seismic capability of the plant. As part of the SEP, the seismic design of the plant has been reevaluated for a safe-shutdown earthquake having a zero-period ground motion input of 0.67g, comparable to that for Units 2 and 3 at the same site. The seismic upgrading of the plant performed so far ensures that the plant can reach hot shutdown in the event of a 0.67g earthquake. The necessary analyses and plant modifications, if needed, to achieve cold shutdown and to provide accident mitigation will be completed by the end of the next refueling outage. We find this satisfactory.

Use was made of a limited Probabilistic Risk Assessment (PRA) in connection with the NRC Staff's evaluations. Since a plant-specific PRA was not available for the San Onofre plant, the techniques used were similar to those used in similar circumstances for other plants in the SEP. As in those other cases, we believe that the NRC Staff's use of PRA was appropriate and that suitable use was made of the results.

Our conclusions regarding the SEP review of the San Onofre plant are as follows:

1. The SEP has been conducted in such a manner that the stated objectives have been achieved for the most part for the San Onofre plant.
2. The actions taken thus far by the NRC Staff in its SEP assessment of the San Onofre plant are acceptable.

3. The ACRS will defer its review of the full-term operating license for the San Onofre Nuclear Generating Station, Unit 1 until the NRC Staff has completed its actions on the remaining SEP topics, including the seismic upgrade, and the USI and TMI Action Plan items.

Sincerely,

David A. Ward
Chairman

References:
1. U. S. Nuclear Regulatory Commission, "Integrated Plant Safety Assessment Systematic Evaluation Program, San Onofre Nuclear Generating Station, Unit 1," USNRC Report NUREG-0829, dated April 1985
2. Safety Evaluation Reports for topics for the San Onofre SEP (3 volumes) transmitted to D. A. Ward, Chairman, ACRS, from J. C. Wolinski, NRC, dated April 27, 1985
3. U. S. Nuclear Regulatory Commission, "Safety Evaluation Report, Return to Service Plan, San Onofre Nuclear Generating Station, Unit 1," dated November 1984

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

AUG 26 1985

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Mr. David A. Ward, Chairman
Advisory Committee on Reactor Safeguards
U. S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Mr. Ward:

In your letter to Chairman Palladino dated August 13, 1985, the ACRS presented its views on the Systematic Evaluation Program as applied and presented in the draft Integrated Plant Safety Assessment Report (IPSAR) for the San Onofre Nuclear Generating Station, Unit 1. In summary, that letter supported the staff's positions.

The staff will revise the draft IPSAR to reflect the additional information provided by the licensee, respond to the recommendations and comments made by the staff's consultants, and incorporate the licensee's schedular commitments. The final IPSAR will also confirm that there are not areas of disagreement remaining between the staff and licensee, as discussed during the ACRS meeting.

Sincerely,

Bill

William J. Dircks
Executive Director
for Operations

APPENDIX I

CONSULTANTS' COMMENTS ON DRAFT NUREG-0829 AND STAFF RESPONSE

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HERBERT S. ISBIN

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May 8,1985

To: C. R. Grimes, Chief
Systematic Evaluation Program Branch
Division of Licensing, Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

From: H. S. Isbin H. S. Isbin

Integrated Plant Assessment Report
San Onofre Nuclear Generating Station, Unit 1
NUREG - 0829 (Draft)

San Onofre Nuclear Generating Station, Unit 1 is the tenth and last plant to be reviewed in the Systematic Evaluation Program (SEP). Review of draft NUREG-0828 (Big Rock Point Plant) occurred more than one year ago. Unlike all previous reviews, for this case the SEP Staff identified one topic which required prompt action, resulting in an extended plant shutdown. With a format now well established by past experience, the SEP Staff narrowed the topics to be reviewed to 36, and agreement with the licensee has been reached in all issues for which a response from the licensee has been received. Only two issues need be resolved.

My review is limited, and I offer the following observations. In my opinion, SEP has achieved its objectives,with the remaining task of establishing with the licensee a "living schedule" for integrating "all" issues yet to be fully demonstrated. A start was made with the Big Rock Point Plant, and hopefully progress is being made for the SEP supplements which are needed to complete the reviews of the ten plants. The "living schedule" must go beyond SEP-identified issues and must include the Unresolved Safety Issues, the Three Mile Island Action Plan Items, other generic issues, and opportunities for plant-initiated improvements. Improvements for extending plant life, for increasing plant reliability (and hence safety), and resolution of problems associated with aging need be given appropriate priority. Flexibility must be provided in scheduling items, and due attention given for best use of both plant and NRC resources.

I view the NRC's Systematic Assessment of Licensee Performance (SALP) report as a key indicator of good management of the San Onofre units, although not enough details are given to single out performance with Unit 1. The trending of the ratings are available.

Future Resources Associates, Inc.

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4 June 1985

Mr. Christopher I. Grimes
Chief, Systematic Evaluation Program Branch
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Mr. Grimes:

This letter comprises my report to you under contract number NRC-03-83-099, FIN. B-8636, and is a review of Draft Report NUREG-0829, "Integrated Plant Safety Assessment Report, San Onofre Nuclear Generating Station, Unit 1." I received the report on 3 May and am pleased to be able to report to you about my review.

INTRODUCTORY COMMENTS

I have found that this SEP assessment has been well done. It is put together well, and is therefore easy to read and to use. The logic of the SEP review process is well established, and is followed effectively.

There is much reliance on the analyses and studies of the licensee (Southern California Edison). I consider this reliance to be fully appropriate. There is no reason why the regulatory staff should need to perform the many analyses itself, and I therefore endorse the approach of staff reviews of licensee analyses. I believe that the staff has done a good job of balancing here, in the sense of carefully selecting for its own thorough analysis only those key issues that really matter.

I note only a few places where there is a difference of opinion between staff and licensee. This is seemingly a good sign (on its face), although it is fair to note that there is no way for me to know how much of the licensee's concurrence is of its own free will and how much is due to a necessity to compromise in order to get the review over with. I assume that the situation is mainly the former but that some elements of the latter do creep in !

I am pleased at how well the 'living schedule' concept seems to be working, at least in this case. The use of an integrated schedule, not only for modifications from the SEP program but for all NRC actions with the licensee, is a vast improvement. This approach should be applied universally.

I found the PRA analyses very useful, and the way they are folded into the decision process in the integrated assessment to be excellent. I will comment on the PRA analysis itself in detail below. The insights from the PRA seem to have been of use in many topic areas.

KEY CONCLUSIONS

My most important conclusion from studying this integrated assessment is that SONGS-1 is in almost all aspects complying with current regulations, or with their intent. Where differences exist (mostly arising from the vintage of the plant), they are in almost all cases resolvable without the need for important physical backfits. Since this issue is the central reason for having undertaken the SEP review of this plant, it is reassuring to be able to report this conclusion.

My judgment in support of the above conclusion is based on my own opinions as to the safety significance of the issues covered. I do not find much in the review that arouses my concern in terms of overall safety of the plant. I believe that the plant does conform well now to the safety levels that are achieved in the broad population of plants in the U.S. In fact, SONGS-1 conformed well before the SEP-induced changes, in my view, and the few changes called for from this review have merely added minor additional confirming procedures and equipment to a plant that has been doing very well all along. I admit that I have introduced my own personal biases here, in the sense that I have a personal agenda as to what is and isn't important to safety --- what I am saying is that SONGS-1 does very well using my own yardstick.

Of course, this key conclusion could not have been known before the SEP review was undertaken. This demonstrates its value.

The methodology used for the SEP review is also fully acceptable, in my view. This is another important conclusion.

AN INTERESTING OBSERVATION

Quite apart from the rest of this review is an observation on my part that the time between issuance of the CP and the issuance of the POL was just over three years. This means that the construction crew and construction management were probably able to follow the job through, start to finish, with a continuous personal presence by the key management individuals. I believe that such a schedule must have been a key element is achieving a plant with overall safety levels that are quite high --- and the observation, 1½ decades later, that the plant was built well is a credit, in part, to both the quality of that construction effort and the fact that it happened over so short a time.

O tempora ! O mores !

REVIEW OF OPERATING EXPERIENCE (APPENDIX F)

The overall impression of the review of SONGS-1's operating history is that not many important operating problems have appeared in the 18 years since the POL was issued in 1967. One particularly important manifestation of that is that there have been no offsite radioactivity releases in excess of Tech Spec limits. Another manifestation is that there haven't been important 'near misses', in which partial failures of equipment or procedures have partially compromised the plant's overall safety importantly.

There have been a few interesting events, to be sure --- as is true of all operating plants. I will comment on a few of these below.

The time-trend analysis doesn't show too much of concern. The overall time trends are pretty flat, with two exceptions: first, there were a large number of difficulties with the inverters until about 1979, when the plant crew seems to have finally eliminated this issue (which affects availability of crucial power). Secondly, the mid-1970s showed increasing problems with steam generator tubing issues, which finally resulted in a major and costly shutdown in 1980-81 for repairs. Neither of these issues is still present at SONGS-1, and when present neither was of sufficient concern to constitute a 'serious safety problem', in my view --- although each is in an area where there is cause for concern.

Some of the early experience revealed design problems that were solved after they were discovered. This is a natural course of events. There is no indication from what I read in this report as to whether the 'lessons learned' from the problems were sent around to other plants so that they too could profit from the experience. I hope that this was accomplished but cannot be sure --- and in fact I am not at all sanguine that this happened, considering that the design flaws were mostly discovered many years ago, before there was an acceptable industry-wide system for disseminating such information.

One apparent design flaw was overloading of cable trays, leading to the fires in 1969 that shut down SONGS-1 for about 6 months. The cable trays were extensively re-done after the fires and presumably the problem is gone. Was this lesson learned by other plants too ?

Another apparent design error was revealed in early 1975. The failure of either one of the two feedwater pump discharge valves to close could have sent safety-injection water to the steam generators instead of to the reactor vessel. This problem was fixed once recognized, but did constitute a possible compromise of the plant's safety-injection capability under certain circumstances. Again, it is worth asking if this problem was analyzed and the analysis sent to all other relevant plants ?

A third design problem was discovered recently (1981): a transient event revealed that the SI injection valves did not meet design pressure requirements and under certain circumstances would fail to open when necessary. This has been fixed.

There has also been an actual loss of onsite (diesel) power capability, due to maintenance problems, in 1981. Apparently there was a problem with the procedure for checking oil levels. While Tech Spec limits were not exceeded, this is an example of how a minor area can lead to a possible important system compromise. Of course, there was no actual safety compromise.

Overall, I conclude from the review of operating experience that SONGS-1 has had about average, perhaps above average performance in terms of its overall safety operating record. This is a high commendation, because the overall industry average performance has been quite good.

I wish (tongue-in-cheek) that certain of the details in the Appendix F write-up were more explicit. What was the rodent doing on Nov.7, 1979 when he (she ?) bridged two energized phases of 480-volt bus no. 1 ? (See page F-73). Was it a tiny rodent (a baby mouse), or a large one (do they have beavers down there ?), or what ? Was there food lying around to attract the mouse (or beaver) ? In my own house, the presence of 'rodents' is an indication of housekeeping problems, typically. Is this true at SONGS-1 also, or was it only a one-time beaver who got lost ?

I have one explicit comment about the text. On page 1-8, there is a discussion of NRC's SALP review. There are three categories in which the SALP board's conclusions are set down. The report (pages 1-8 and 1-9) indicates that there were five areas falling under category 1 and five falling under category 2. I believe the report would be strengthened if there was an explicit statement that no areas fell under category 3. This is in the nature of giving credit where credit is due. My modification would be simply to add "Category 3: none" to the text on page 1-9.

THE PRA ANALYSIS (APPENDIX D)

I found the PRA analysis to be generally well done. Of course, there has been no 'full-scope PRA' accomplished for SONGS-1, so that the analysts were required to carry out various limited PRAs on the specific issues that came before them. These limited PRAs were mostly in the form of fault trees that were developed to understand the relationships among different aspects of a problem.

The analysts also used insights from other PRAs (on other plants) where these insights were applicable. I am quite familiar with the PRA literature and I believe that the analysts did a good job of using what is known, and of recognizing its limitations.

There was one general comment about the analysis that I think is worth making. This is that the analysts frequently used WASH-1400 data, although it is about ten years old, for their quantifications. In some cases, there is newer information. While I do not think that any conclusions would be altered by the use of the newer data, I was struck by this. I believe that newer data should be used, in general, where available.

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There were a few places where I think the PRA analysis write-up could have been improved. An important area is that of precision: often the numbers in Appendix D have more significant figures (sometimes three) than is merited by the analysis or by the underlying input data. I believe that this is inappropriate and conveys the wrong impression to the uninitiated. My own rough estimates agreed with the numerical results of the PRA write-up wherever I tried to duplicate the results, showing that there were not any numerical errors in the several quantifications that I checked.

Another general comment on the write-up concerns the use of sloppy and confusing notation, and the lack of units. In several places the text cites a probability of such-and-such per year. This isn't correct, in my view. In PRA terminology, a probability should always be dimensionless, such that perfect performance means probability of 1.0 (or 100 %). The frequency of something like an error is what should be cited as such-and-such per year. Availabilities should be some number on demand, occasionally per year. This write-up was often confusing to me, although in the end I did figure out what was what. How a non-expert could figure it out is beyond me !

I do not agree with a comment made in the methodology section of the PRA write-up. Specifically, on page 2 (under section II) it is stated that seismic, tornado, and flooding are excluded because "the frequency of a given severity event, or any such event, is not well known." This is not a good rationale for excluding external initiators. In actual fact, the frequency of many of these is known every bit as well (or as poorly) as the frequency of certain 'internal initiators' (such as large LOCA) that are routinely analyzed. Furthermore, the methodology for treating these external initiators is now sufficiently mature that they can be done about as well as the internal initiators --- see the discussion (which I wrote !) in NUREG-1050, the recent "PRA Reference Document".

I do agree with omitting analysis of areas in which the phenomena are not well known. This is acceptable, especially when recognized.

I very much like and endorse the three-phase approach that is outlined on pages 3-4 of the write-up. This allows a rough screening to be accomplished before any full PRA analysis is launched.

Finally, I like the Executive Summary very much indeed. The concept with which it was prepared is great, and it is superbly executed. It is rare that an executive summary does as fine a job of summarizing the contents of a report !

Of course, there is the inevitable problem that some issues cannot be treated using PRA methods. In particular, some issues are important in a regulatory sense even though there is no directly calculable core-melt frequency or system unavailability that PRA analysts can get a handle on. For this reason, there are a couple of areas where the PRA write-up isn't of much use to the overall assessment. That is OK; PRA is good for lots of things, even if not for everything.

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COMMENTS ON SPECIFIC TOPICS REVIEWED IN THE "INTEGRATED ASSESSMENT"

The integrated assessment for SONGS-1 covers about three dozen topics, of which about half are also covered in a supporting PRA-type analysis. In actual fact, the number of topics including all the sub-topics is larger than three dozen,perhaps double.

I will comment below on some of these topics and sub-topics. There will not be comprehensive coverage of all topics, and the reader can assume that when a topic is not covered my opinion is in agreement with the outcome of the assessment, except for a very few which I didn't understand enough to study.

I have a comment to make about the introductory text (page 4-1) that precedes the actual description of the integrated assessment. In particular, in discussing the PRA analysis, the text states:

> "This risk perspective has been used to judge the importance of the identified differences in relation to accident sequences leading to core melt, with due consideration of the uncertainties in the PRA techniques."

I believe that it is high time for a comment about how unbalanced this little section is. Specifically, there is "due consideration given" to the PRA uncertainties, recognized explicitly in the text, but no such comment is made about uncertainties in other aspects of the analysis. But we all know that other analytical methods also have uncertainties too. And we also know that the regulatory staff has tried, as best it can, to be sure that "due consideration" is given to them !

Why is PRA singled out for the clause about "due consideration" of uncertainties ? I, for one, know the answer, and it is really a crazy and vestigial bit of entrail from the days when PRA was so controversial ---days now long since past, thank the Lord. It is easy to remember the situation: Hal Lewis' so-called "Lewis Report" (of which I was one author) explicitly stated that the uncertainties in WASH-1400 had been understated, and the follow-on Commissioners' "policy statement on PRA" explicitly endorsed the widespread use of PRA in NRC decision-making, taking due account of uncertainties. Ever since that golden moment in 1979, it has been obligatory for all staff documents which use PRA to include the little prayer about uncertainties. Like certain other religious and superstitious practices, it is guaranteed not to do any harm and thought possibly to do some good some of the time --- like carrying a rabbit foot.

I suggest that this little bit of historical nonsense be dropped, or alternatively that it be broadened so that staff documents recognize uncertainties in other types of analyses as well.

I'm sorry for the diversion --- but I just don't get chances to say these things often enough, in print, where at least somebody might read 'em.

Section 4.1 (Topic II-1.C), Offsite Hazards

In section 4.1.1 the text cites that SONGS-1 "calculated" a frequency of 4.5 x 10^{-6}/year for exceeding 0.5 psi overpressure for nearby explosions. Then it goes on to say that SRP section 2.2 allows a licensee to sharpen his pencil if the calculation exceeds the acceptance criterion. This pencil-sharpening was dutifully done and "sufficient conservatisms" were identified to warrant a no-backfit decision. I believe that the text would be strengthened if the conservatisms were identified briefly in the text. What are they ? Why didn't SONGS-1 get a lower number at first, especially if they knew that the acceptance criterion is 1 x 10^{-6}/year ? Are the arguments really "qualitative", as stated in the text, or do they include certain quantitative arguments as well ?

Section 4.5 (Topic III-2), Wind and Tornado Loadings

My initial reaction to this section was to feel upset that the staff in its TER recommended as a design basis that tornado whose recurrence return period is 10^{7} years. This seems much toosevere a criterion to me ---- aren't we all pretty much agreed now that our target core-melt frequencies are in the range of 10^{-5} per year, or maybe 10^{-4}/year ? Why be so conservative ?

In reading the details, I also observed that there is a difference of opinion in the professional community about what actual windspeed corresponds to 10^{-7}/year. This is not surprising --- I recall finding this was also true at Indian Point. Shouldn't the staff use a more realistic recurrence interval like 10^{-5} or 10^{-6}/year, and put consevatisms into the engineering analysis too to assure that structures and equipment can survive that wind well ?

I am pleased that, in the end, the staff is going along with a 'cost-benefit' approach to the evaluation of what might be fixed. But I am not pleased with the excessive conservatisms on the hazard side.

Section 4.13 (Topic III-7.D), Containment Structural Integrity Tests

The approach taken here shows admirable restraint, and in my view is the proper approach. Specifically, it is reasonable to observe and conclude that steamline breaks don't degrade containment as much as do postulated large LOCA breaks, and SONGS-1's evaluations do show that double-ended main steamline breaks are not credible. This is a valid basis for the staff's restrained position.

Section 4.14 (Topic III-8.A), Loose-Parts Monitoring

Given what I know from the loose-parts events in the operating record, I am mystefied at how this item remains in the regulations. I agree with the conclusions of the PRA that this is not a risk-significant issue. I am pleased that the outcome of this issue is no new requirements, since in my view they would not be cost-effective.

Section 4.15 (Topic III-10.A), Thermal-Overload Protection for Motors of MOVs

The PRA analysis concluded that bypassing the thermal-overload protection only changes the MOV failure probability on demand by 14%. This is judged to be small. However, the numerical result is suspiciously uncertain in detail. It comes from substracting the MOV failure rate given in WASH-1400 (1.0×10^{-3} per demand) and the calculated 4×10^{-7}/hour failure rate of a thermal relay, times the hours per monthly test interval. Neither of the numbers being subtracted has precision beyond about one significant figure (if that !), especially since these numbers are generic, not specific to the MOVs in question. Thus the subtraction (1.0×10^{-3} minus 1.4×10^{-4}), which gives the 14% change from the 1.0×10^{-3} value, is of only limited quantitative value.

Luckily, the staff has another technical rationale for making its decision, namely the ability to operate the valves manually. This is a case where PRA analysis gives quantitative insights that are of only qualitative use --- and the insight is this case is that the 14 % number could just as easily be 1% or 100 %, which is of very little use.

Section 4.17 (Topic IV-2), Reactivity Control Systems

I concur fully with the resolution of this item. I wish to comment here about a typical situation where PRA analysis, while useful, is not an adequate basis for a regulatory decision. The PRA analysts essentially dismissed this issue on the basis that core melting was not involved, and hence risk is low. However, there is good reason to rely on the General Design Criterion 25 to ensure that fuel design limits are not exceeded. There is no conflict here, only a difference of perspective dictated by a difference in scope --- PRA cannot cope with non-core-melt accidents, but engineering codes must be applied for another reason !

Section 4.18 (Topic V-5), RCP Boundary Leakage Detection

Under section 4.18.1.2, the staff position is that Tech Specs are "necessary to ensure operability of the leakage detection systems, and, therefore, timely detection of leakage from the reactor coolant system." While the licensee has agreed, I think this may be overkill. Is a Tech Spec really necessary to ensure that these systems will work ? How much unavailability is tolerable ? How much would occur without Tech Spec changes, and how much 'better' will the availability be with them ? I don't know the answer to these questions, but I suspect that whatever problems will occur (with only low likelihood) are not likely to be improved by writing Tech Specs into the license. I think an analysis of what the sources are of residual unavailability might reveal that Tech Specs won't achieve the desired result. Has there ever been any other analysis of how Tech Specs affect availability of leakage detection systems ?

Section 4.21 (Topic V-11.B), RHR System Interlock Requirements

The discussion under 4.21.2 (overpressure protection of RHR system) concludes that the current configuration was acceptable although it deviates from current licensing criteria. However, the staff desires to impose a Tech Spec change "to provide protection for the RHR system". This is another example of overkill -- regulatory actions with little safety benefit, done for the sake of themselves. I would not make a Tech Spec change here.

Section 4.23 (Topic VI-4), Containment Isolation System

Under the discussion of the PRA results in the main text of section 4.23, it is stated that although the PRA showed only low risk importance, "the PRA did not consider the potential benefits that could be derived by mitigating leakage for non-core-melt accidents". In terms of protecting the health and safety of the public, what are they ? Or is it for occupational dose reduction (if so, that should be cited.) ?

The overall analysis of the topics under this section is very good, and the judgments of the staff fine, except for the item cited above. I particularly like the discussion under 4.23.1.4, 'automatic loading of DG radiator fans."

Section 4.24 (Topic VI-7.B), ESF Switchover from Injection to Recirculation

The outcome of this assessment is excellent. I think this issue demonstrates well the value of the SEP review, since an important improvement has been achieved at little cost. The setpoint change for the RWST is just the proper approach to give more time for manual action if needed.

However, the PRA analysis, while fully correct, cites an accuracy that is a little greater than justified by the analysis itself. The 'factor of 7' must be taken with a grain of salt, in my view, since the input numbers include some whose accuracy cannot be very great, such as the OPE1 and OPE2 values cited in the PRA analysis (page 59).

Section 4.26 (Topic VI-10.A), Testing of Trip System and ESF, Including Response Time Testing

The conclusion under 4.26.1 is that response-time testing of the RPS is not required. This is based in part on the sufficiency of functional testing, and partly on the low risk significance found by the limited PRA study. However, the staff wants Tech Spec changes to cover RPS testing anyway ! The licensee agreed. This is still another overkill example in my view.....the testing is in plant procedures already, isn't it ?

Section 4.30 (Topic VIII-3.B), DC Power System Bus Voltage Monitoring/Annunciation

The staff's agreement that an inspection program is acceptable here, as a way of asssuring that 125-volt dc bus failures would be reduced, is a good resolution. These systems are important to risk in most PRAs.

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Section 4.32 (Topic IX-3), Station Service and Cooling Water Systems

Something here piqued my curiosity. Under 4.32.4, the text states that "the licensee has determined......that the tsunami gates need not be closed to prevent site flooding in the event of a tsunami.....Accordingly, the licensee has removed the tsunami gates." What I'm curious about is what might have changed to bring about this conclusion? Do we now think tsunamis at that site are smaller than was thought when the tsunami gates were designed ? Or are the gates ineffective ? Is the reactor higher than thought, or its critical equipment more protected ? The text doesn't say.

Section 4.33 (Topic IX-5), Ventilation Systems

I find the resolutions of all the items in this section acceptable. I wish to point out that almost every one of the SEP reviews has found important differences between the ventilation systems in place and those desired for safety reasons. The changes have mostly been made, or will be. Has the staff learned a generic lesson here and asked any other licensees to look at these ventilation systems ?

Section 4.35 (Topic XV-1), Feedwater Flow, etc.

The commitment by the licensee to do more analysis of the increase-in-feedwater-flow issue is appropriate here. This could be an important safety concern, and only analysis will tell us to what extent.

CONCLUSION

The above concludes my review of the SONGS-1 draft integrated SEP assessment report, NUREG-0829. I wish to commend the staff and its contractors (SAI, ORNL, ORNL's subcontractors) for a very nice job. Despite my seemingly critical comments above, my overall impression remains very favorable. Congratulations !

Sincerely yours,

Robert J. Budnitz

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July 19, 1985

Mr. Christopher I. Grimes, Chief
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Mail Stop 516
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Washington, D. C. 20555

REF: Integrated Plant Safety Assessment
San Onofre Nuclear Generating Station, Unit 1
Systematic Evaluation Program

Dear Mr. Grimes:

This letter is my technical evaluation report on the San Onofre Unit 1 Integrated Plant Safety Assessment, as given in the draft report NUREG-0829. It fulfills the requirements of the eighth and final work assignment (San Onofre 1) of Revision 1 of the project, "Consultant Services, Dr. J. M. Hendrie to Review SEP Integrated Plant Safety Assessment Report," FIN A-3367, B&R No. 20-19-20-21-1.

CONCLUSIONS

The draft Integrated Plant Safety Assessment Report (IPSAR) on the San Onofre Unit 1 is consistent in treatment with previous reports of the Systematic Evaluation Program. Although the scope of the review for San Onofre 1 is the standard SEP scope, the review has taken a long time and has been particularly difficult because of the seismic capability issue. The San Onofre 1 review has been carried out in accordance with established program directives. It supports my previcus conclusion that the SEP has fulfilled the intent of the Commission when it authorized Phase II of the program.

Detailed comments on the results of the integrated assessment process are given below. In general, I find the staff recommendations for backfitting, or for not requiring backfitting, to be reasonable and appropriate and the bases for those recommendations to be adequate.

A limited probabilistic risk assessment (PRA) study has been done by the staff's consultants for a number of SEP review topics. The results provide valuable insights into safety issues that would not be available otherwise.

Some of the staff recommendations for San Onofre 1 at this stage of the SEP review are for further analysis and evaluation by the licensee. The results of these analyses and evaluations will require some further decisions by the staff as to whether or not backfitting of some kind is needed. These further decisions should be made on the same integrated assessment basis as those given in the draft report.

Also, a number of the original 137 SEP safety topics are being treated generically under the Unresolved Safety Issue program, the Three Mile Island Action Plan program, or other regulatory generic programs such as implementation of Appendix I to 10 CFR 50. Most of these topics are not covered in the San Onofre 1 SEP review in NUREG-0829. Resolutions of these topics that are specific to San Onofre 1 will be needed eventually. The generic resolutions of these topics should be applied to San Onofre 1 through the integrated assessment process.

DISCUSSION

THE STAFF SAFETY REVIEW

The intent of the SEP review is to examine a chosen plant against current licensing criteria and practices in 137 safety topic areas. These 137 topics are listed in Appendix A of the report. Where deviations from current criteria are found, there are a number of alternatives, or combinations of alternatives, that may be considered as a basis for acceptability. These include acceptance of the deviation because it does not significantly decrease the plant safety level, use of non-safety-grade systems to perform safety functions, administrative or procedural changes to enhance safety system reliability, augmented surveillance programs for the same purpose, and selected backfitting. Deviations from current criteria are acceptable if staff evaluations show that the plant would respond satisfactorily to the various design basis events and that the probability of those or the consequences are not significantly higher than for plants now being licensed in accordance with current criteria.

The standard SEP review of San Onofre 1, based on the 137 SEP safety topics, is summarized in Sections 3 and 4 of the report. In the review, 48 topics were deleted because they did not apply to San Onofre 1 (the 24 topics listed in Appendix C) or because they are being covered by other staff groups on a generic basis (the 24 topics listed in Appendix B). The latter group of deleted topics is composed of Three Mile Island Action Plan items and unresolved safety issues. The 48 deletions from the standard review are appropriate and are consistent with other SEP reviews.

The 89 SEP topics reviewed for San Onofre 1 resulted in staff judgments that the plant meets current criteria or is acceptable on some other defined basis for 53 topics. The remaining 36 topics were considered in the SEP integrated assessment process, to determine what actions should be taken to deal with the identified deviations from current criteria. The results of the integrated assessments for those 36 topics are given in Section 4 of the report.

The staff identified one safety issue requiring immediate action. In reviewing the seismic design, some high calculated stresses raised a question as to whether the unit met the licensed design basis for seismic capability. The staff decided not to permit restart from an extended outage that was in progress (early 1982) until the matter was resolved. Rather than argue the matter, the licensee undertook to upgrade the facility to current criteria. Two and a half years later (late 1984) the upgrade, and review of same, had progressed to a point where the staff permitted restart.

COMMENTS ON THE INTEGRATED ASSESSMENT RESULTS - SECTION 4

4.1 Topic II-1.C: Hazards from offsite. Explosions on nearby highways or railroads of a magnitude to be safety-significant were judged, correctly in my view, to be of too low a probability to merit counter-measures. The likelihood of toxic gases from accidents on the same highways and railroads is also low, but the staff asked for cost-benefit studies of improvements to the single-train, manual isolation only, control room ventilation system. Apparently, nothing attractive resulted and the staff is currently thinking about toxic gas monitors. My experience with these things is that toxic gas monitoring technology is none too good. The things alarm gratuitously and are constantly getting out of whack. If there is an automatic control room isolation based on toxic gas monitors, there is a steady stream of isolations. It is a non-trivial distraction for operators, and hence a safety consideration. If toxic gas monitors are to be required, which I do not advise, then let the Tech Specs recognize the nature of the technology and not ask too much. Canaries would be better.

4.2 Topics II-3.A, B, B.1, and C: Flooding of various kinds. No problems noted except for an evaluation of ponding loads on flat roofs in probable maximum precipitation situations. (But see 4.6.) I used to think the staff's rainmakers were too fussy about this item, but lately I've had some jobs near the Gulf Coast and have revised my concepts of how much water can come out of the sky on occasion.

4.3 Topic II-4.F: Foundations, backfill, etc. The staff has still to review modifications made by the licensee to improve backfill load carrying and seismic characteristics under some safety-related structures. Presumably this is well in hand and the licensee has been keeping the staff informed of these measures as he has gone along. (Witness staff conclusion that the seismic upgrading of the unit justified the restart last year.)

4.4 Topic III-1: Seismic and quality classifications of structures, components, systems. Like all the other SEP Phase II plants, San Onofre 1 is old enough to have been built to codes and standards that have, in some cases, been much changed over the years. Now the old plant is to be compared to the new codes. The staff has prescribed a fairly extensive set of evaluations to be done by the licensee to cover areas where it is not apparent from currently available documentation that the plant meets the new codes. This has been the standard treatment of this review topic throughout the SEP reviews. The burden is helped somewhat by a reasonable schedule for the evaluations. I take it from the discussion in the draft report that the licensee has agreed to the evaluations in principle, and what now remains to be settled before the final IPSAR are the detailed evaluation plans for each area. Good enough.

4.5 Topic III-2: Wind and tornado loadings. The initial topic review resulted in staff recommendations that a 75 mph wind and a 10^{-7} per year, 260 mph tornado be used for the site and structures strengthened accordingly. Since then the licensee has done an analysis showing the 10^{-7}/yr tornado at 183 mph and the staff has had two further analyses which have come out at 270 mph at the upper 95% confidence level.

While 10^{-7}/yr probabilities and 95% confidence levels could be appropriate for new designs (a point worth arguing, but not here), the combination seems excessive for SEP plants. With a probability as conservative as 10^{-7}/yr, there is no need to move all the way out to 95% confidence level on the frequency distribution. Or, if you like the 95%, then move up to 10^{-6}/yr or so. However, the final outcome will be more reasonable than these statistical standards indicate, since it will be based on evaluations of risk abatement vs. cost and determined in the context of an integrated plant safety assessment. In past SEP reviews I have found the final staff agreements on upgrading wind and tornado protection to be prudent and reasonable. I expect the same here.

4.6 Topic III-3.A: Structural aspects of high water. One already noted (in 4.2) is ponding loads on flat roofs. The other is groundwater level for design basis purposes. The staff wants an evaluation of groundwater at grade (taken to be 5 ft. MLLW) for short-term hydrostatic loads, and whether that would lead to physical plant modifications and if so, what and when. That is the usual SEP approach and is reasonable.

The abbreviation MLLW, by the way, stands for "mean lower low water" and not "mean low level water" (p. 4-7).

4.7 Topic III-3.C: Water control structures, inspection of. Staff and licensee have pretty well agreed on the subject inspections. No problems here.

4.8 Topic III-4.A: Tornado missiles. The tornado missile spectrum will be included in the evaluations under 4.5. The staff's usual (and appropriate) bottom line in this area -- to have enough tornado wind and missile-protected gear around to shut down and maintain safe shutdown -- is applicable. O.K.

4.9 Topic III-5.A: Pipe breaks inside containment. The licensee is to make analyses of identified places where safety-related equipment could be affected by broken pipes inside containment. These analyses will include fracture mechanics analyses, which presumably will show here, as at other plants, that one may depend on the "leak before break" approach. In view of the undesirable effects on operability, inspection, and maintenance of cramming massive pipe whip restraints and shields into an existing containment, the latter approach should be used wherever possible.

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4.10 Topic III-5.B: Pipe breaks outside containment. The same situation and comments as in 4.9 apply here.

4.11 Topic III-6: Seismic design. The seismic upgrading of San Onofre 1, which has been the dominant element in the SEP review, is well along and there do not seem to be items remaining of any great uncertainty or contention. There are more analyses, and probably some resulting modifications, to come on equipment for cold shutdown and accident mitigation and to provide a basis for long-term operation. The modified Housner spectrum at 0.67 g is an adequately conservative basis for the seismic reevaluation that has gone on. For piping it is more than adequate, I think, but it is hard to avoid the o.67 g reference point with units 2 and 3 pegged there. Overall, a difficult review area for this unit but one working out in a reasonable way.

An editorial nit: "seismic Category I" rather than "A", p. 4-10, last paragraph.

4.12 Topic III-7.B: Codes, criteria, load combinations, etc. Here again, changes in codes from the days of San Onofre 1's building to the present have to be confronted. The main emphasis here is on structures and the possible effects of code changes are considered in the context of all the other structures-related evaluations. This makes for an efficient, integrated handling of the assorted structures issues, one of the progressive developments of the SEP reviews. For this case, the seismic re-analysis of structures has been extensive and the modifications sufficient to dominate most of the structures issues. There are some further evaluations due from the licensee in this area, but it seems well in hand.

4.13 Topic III-7.D: Containment structural integrity tests. The staff has correctly decided that past containment pressure tests are adequate, in spite of various revisions of accident calculations that have yielded slightly different and higher calculated peak accident pressures. Recent studies of containment structures in connection with source term reevaluations have shown how much more robust these structures are than we had given credit for.

4.14 Topic III-8.A: Loose parts and core barrel vibration monitoring. As in other SEP reviews, it is found that installation of loose parts monitoring equipment would not reduce any risks enough to justify the cost. So the staff concludes nothing further is needed on this issue. I agree.

The draft report is silent, aside from the topic title, on core barrel vibration monitoring. I assume that was found not to be cost-effective also.

4.15 Topic III-10.A: Thermal overload protection of motors on safety-related valves. The point here is to make sure that the thermal overload protection normally installed on electric motors does not, in the case of safety-related valve operators, defeat needed valve actions in an emergency. The SEP has established a standard and sensible protocol for achieving this end. At San Onofre 1, only two valve motors were not in conformance. These were allowed to remain unmodified in view of the configuration, which reduces the risk significance of failure of these valves, and ready access for manual operation. O.K.

4.16 Topic III-10.B: Pump flywheel integrity. The licensee has instituted an inspection program that meets the recommendations of the applicable Regulatory Guide. No issue here.

4.17 Topic IV-2: Reactivity control, notably the control rod system and possible single failures thereof. Various single failures of the control rod system were identified under this topic, but none had consequences outside the control rod misoperation accidents considered in the accident analysis. Since these were acceptable, the single failures also have acceptable consequences and are low risk sequences. The staff concluded that nothing more than the analysis was required. I agree.

4.18 Topic V-5: Primary leak detection. A subject of some concern in these reviews in view of leak-before-break arguments made to justify not having pipe whip restraints. An adequate array of leakage detection systems becomes a pre-requisite for that approach to primary pipe breaks. At San Onofre 1 there are assorted ways to detect primary leakage, but some upgrading was found necessary in the staff's view. The sensitivity of detection was found to be adequate, provided the section 4.9 analyses come out all right. Operability of the leakage systems was felt to require Tech Spec provisions. I am generally against adding to the Tech Specs, but the requirement here is consistent with previous SEP practice. The staff also wants at least one detection system to be operable after a safe shutdown earthquake. The licensee has agreed to provide one and it does not seem inappropriate at this site. Two of the San Onofre 1 detection systems can be tested during operation and the primary system hot leak rate test procedure can back up a third (sump level). This was considered sufficient for the testability requirement. I agree. Intersystem leakage detection was also examined and found adequate.

4.19 Topic V-10.A: RHR heat exchanger tube failure. The staff concluded that primary (radioactive) leakage through a tube failure in the RHR heat exchanger to the component cooling water (CCW) and from there to the salt water cooling system to the environment via a CCW heat exchanger tube failure was possible (the pressure differences system-to-system during operation favor it), but unlikely enough so as not to require further measures because the CCW system is monitored for such leakage. Salt water in-leakage during shutdowns, when the pressure differences are reversed, was also considered a non-problem for the same reasons. I agree.

4.20 Topic V-11.A: High and low pressure system isolation. Three low pressure systems at San Onofre 1 were found not to meet current criteria for protective isolation from the high pressure primary system. However, detailed examination of possible isolation failure sequences showed them to be very unlikely and it was concluded that no further measures are needed. The reasoning seems sound to me.

4.21 Topic V-11.B: RHR pressure interlocks. The concern here is the same as in 4.20; overpressuring a system connected to the primary system. The San Onofre 1 RHR system does not fully meet current criteria with regard to interlocks, but because the RHR is inside containment, interlocks are provided on two or four isolation valves in series, and the RHR is separate from the emergency core cooling systems, no additional measures are considered necessary. I think that is reasonable. Overpressure protection of the RHR system is by relief valve and by a special overpressure mitigation system. The staff wants a Tech Spec provision requiring operability of the latter system before putting the RHR system in operation, and the licensee seems to have agreed.

4.22 Topic VI-1: Containment coatings. The staff asked for and the licensee agreed to an inspection and paint repair program to keep containment coatings in good shape. O.K.

4.23 Topic VI-4: Containment isolation provisions. Always a lengthy subject in SEP reviews as the differences in these older plants from current isolation criteria are examined to see whether they are substantive enough to require changes. The San Onofre 1 review deals with a series of issues from purge lines and electrical aspects, through assorted fluid system isolation valve particulars, and on to airlocks, hatches, and spare penetrations. A Tech Spec change, some new procedures, and some seismic upgrading and qualification are called for; other issues are settled without need for modifications. I found nothing to argue about in the reasoning and conclusions.

4.24 Topic VI-7.B: Switchover to long-term emergency core cooling. In the event of a loss of coolant accident, the emergency core cooling systems dump water in the reactor vessel to restore and maintain water level and thus keep the core cooled. All that water comes from the refueling water storage tank (RWST). It is a big tank, but eventually it is emptied. Then there has to be a switchover from the injection mode (water from the RWST) to the recirculation mode, in which water is drawn from the containment sump, through a heat exchanger, and is pumped back to the vessel. The switchover is a delicate point in establishing long-term, i.e., recirculation mode cooling. Done too early and the RWST inventory is not effectively used; further, the sump level may not be high enough. Done too late and the safety injection pumps are left cavitating on an empty tank, with the possibility of severe damage. At San Onofre 1, the timing is particularly sensitive due to the high pumping rate of the big safety injection/feedwater pumps. There are several things the operator must do to achieve switchover, at the right time and in a short time interval. The right time is signaled by a single low alarm on RWST level. The staff, properly concerned about the ample opportunity for error in this procedure, has asked for an automatic shutoff of injection pumping at the appropriate RWST level (to save the pumps -- there is ample time then to start the recirculation), and a backup to the present RWST level channel. Some brushing up of switchover procedures and training is also indicated. These cures seem reasonable to me. Failure of the recirculation cooling after a LOCA, including the switchover phase, is found to be a major contributor to the total core damage probability in full-scale risk assessments, so it is not an ersatz concern.

4.25 Topic VI-7.C.2: ECCS failure modes. This topic picked up two pre-SEP reviews of emergency core cooling failure modes at San Onofre 1, as well as the SEP-generated queries. Various single failures were identified; some had already led to modifications and these were reviewed in the SEP and found acceptable, for good reasons. These included a valve in the suction line from the volume control tank, the air supply for safety injection flow control valves, and hot leg recirculation during long-term core cooling. A number of other modifications had been suggested in the earlier single failure studies. Some of these have been adopted or resolved in other topics or studies; the rest are to be studied by the licensee to see if the modifications are justified. Fair enough.

4.26 Topic VI-10.A: Testing of reactor protection system, engineered safety features, and response times. Several issues arose for the integrated assessment. The first was response time testing of the protection system. A limited risk assessment gave small credit to requiring this and, to their credit, the reviewers decided not to impose it. They did find several protection system channels for which testing was prescribed in procedures, but not in the Tech Specs, and requested these tests be put in the Tech Specs. The licensee agreed and I will not raise my customary objection to adding things to the Tech Specs in this case. Similarly, the containment spray actuation logic is not in the Tech Specs and staff wants it in. Again, no objection. For various essential support systems, in-service inspection requirements, together with applicable limiting conditions for operation, were determined to provide adequate coverage and no additions to the Tech Specs are required. Good.

4.27 Topic VII-1.A: Protection system isolation. The reactor protection system at San Onofre 1 is not electrically isolated from recorders and remote meters, nuclear instruments are not isolated from a data logger, and the steam-feedwater mismatch channels are not isolated from the feedwater controls. All of this is not up to current criteria. However, a risk assessment of the benefit of installing isolation devices showed negligible benefit to protection system reliability. Further, evaluations by the licensee showed no dire results from failures in the connected non-protection or other devices. The issues were therefore considered resolved, a sensible outcome.

4.28 Topic VII-3: Safe shutdown systems. The matters of interest here are CCW surge tank level and several aspects of the auxiliary feedwater system. The surge tank level instrumentation is single channel and thus vulnerable to a single failure (a sight glass does provide a local backup). However, a limited PRA showed low risk significance, because the unit can get to hot standby and stay there without CCW, and the staff decided a redundant level channel would not be needed. Seems reasonable.

The auxiliary feedwater questions started with whether the unit had a sufficient supply of water for the AFW in seismic Category I tanks. The licensee installed a large, Category I condensate storage tank to solve that problem. Next was the question of a passive failure of the suction line from the condensate storage tank; the licensee installed a redundant flow path to fix that. The licensee has also agreed to put in a third AFW pump, electrically driven. In the post-Davis Besse climate, one might look to expediting the schedule a bit.

4.29 Topic VIII-1.A: Degraded grid voltage. The subject is protection of plant equipment if there is low voltage on the grid, and includes both cutting loose from the grid and determining when (at what degraded voltage) it is necessary. The licensee has made some changes, is doing some testing in preparation for others, and has committed to a program acceptable to the staff.

4.30 Topic VIII-3.B: DC batteries and power supply system, monitoring of. The staff bought off on the unit's low voltage alarm and breaker/fuse status indication in the control room, and the licensee's procedure to go check the local instruments if those signal trouble. A battery current monitor would be nice, but there does not seem to be one commercially available with both the range and accuracy needed. The licensee has thrown in an inspection program, which helps, but I wouldn't have minded a few more indicators of battery and DC system condition in the control room. It's awfully lonely without at least one of those DC systems in good shape.

4.31 Topic VIII-4: Electrical penetrations. The question here was whether modifications were needed to cure a potential containment penetration failure problem, if there was a LOCA and if the primary protective breakers on low voltage AC and DC circuits penetrating containment failed and if the long operating time of the backup breakers led to overheating the penetrations, if there were faults on those circuits. A limited PRA showed low risk significance, and staff settled for monthly penetration assembly testing. I agree with the low significance. In my experience, four "if" sequences are seldom important.

4.32 Topic IX-3: Cooling water systems. The component cooling water and salt water cooling systems are the matters of interest, with several issues on each. A possible excess temperature condition in the CCW was eliminated by better analysis. (It was only 27°F anyway.) Then a question about independence of a pair of redundant valves came up and the licensee whipped out an old report to the staff that shows the requisite independence. Staff is still looking that over. Finally, passive failures were brought up with regard to the single CCW supply and return lines. However, the licensee has shown he can maintain the unit in hot standby without CCW, a limited PRA gives the passive failures a low risk significance, and the licensee has promised to put in a dedicated shutdown system to solve his Appendix R problems. Good enough.

The salt water cooling system (SWC) issues start with a possible failure of the supply. The greatest part of this possibility has been eliminated by removal of some gates that were to protect against very high waves and have been shown unnecessary. A question of valve independence, similar to that for the CCW, is awaiting staff review of the same 1977 licensee report. Loss of the SWC pump bearing water flush was ruled not a concern when the pump supplier said the SWC pumps could run for many days (30) without the flush. Finally, the question of SWC reliability keeps arising. There has been one case of a loss of all SWC pumps and some other problems. Several modifications have improved the system, but a recent operator error caused the staff to ask for a further evaluation to see if other changes are needed. That seems a worthwhile exercise.

4.33 Topic IX-5: Ventilation systems. Several locations of safety-related equipment were found vulnerable to single failures in ventilation systems, and possible overheating of the equipment in that event. The auxiliary building and the charging pumps were the first issue. A limited PRA showed low risk significance, however, and the licensee's evaluation was that containment purge and exhaust fans could be used in a pinch. It's not clear to me how, if the charging pumps are in the auxiliary building, the containment purge is any help. Or, if the charging pumps are in containment, why the auxiliary building ventilation system is of interest vis-a-vis the pumps. Or, finally, whether it is a good idea to have to run the containment exhaust system in order to keep the charging pumps operable. On the other hand, if charging pump failure doesn't amount to much, none of that is relevant.

The next ventilation issues were the switchgear and cable spreading room and the 480-volt switchgear room. Analyses showed acceptable temperatures in the switchgear cable spreading room in the event ventilation is lost, provided some doors are opened and lights turned off. (Also, new air conditioning units have been installed there to meet Appendix R requirements, although the licensee doesn't get credit for them since they are not safety grade and are not connected to the diesel generators.) The loss of the 480-volt switchgear from overheating was found acceptable, since other systems can carry the plant to shutdown and maintain it. So, no modifications were required, but a room temperature monitoring program and procedures for ventilation system loss will be implemented, which is reasonable.

The last ventilation issue was about the battery and inverter rooms in the administration building. Again, analyses showed acceptable temeratures if the ventilation is lost (and some doors opened? It isn't clear -). Venting hydrogen from the batteries is the main concern, and the staff has requested procedures for making sure hydrogen concentrations do not get out of hand if the fans aren't operating. I'm for anything within reason to protect the DC systems, so would go at least this far.

4.34 Topic IX-6: Fire protection. The licensee has proposed a dedicated shutdown system to solve assorted Appendix R issues. The details are still in staff review (a year after submittal, I point out) by the fire protectors. The SEP issue is, in effect, transferred to the generic Appendix R effort and declared closed for SEP purposes. That is OK, but the proposed dedicated system is of more than passing interest in several SEP topics and it is not a satisfactory situation to have agreement on that system hanging open for an extended period. If the fire protectors can't get around to the San Onofre 1 matter, it should be assigned to the SEP group.

4.35 Topic XV-1: Secondary system malfunctions. The one secondary transient still of concern is excess feedwater, flooding the steam generators and main steam lines. The licensee is analyzing this case to see if anything is needed to keep within design limits should this transient lead to a main steam line break. I wouldn't spend much on this. The chance of a MSL break from flooding the line isn't very large, and if it happened the odds are very large that it would be a crack and not the great double-ended instantaneous break of the design basis event.

4.36 Topic XV-2: Steam line failures. The sequence of interest is a MSL break and failure of the elecrically-powered AFW pump (the other is turbine-driven). This leaves the unit with no feedwater and no afterheat removal until the main feedwater system is realigned to the steam generators (MFW automatically switches to safety injection in an accident). The licensee has agreed to put in a third AFW pump, electrical motor-driven, so that takes care of the single failure vulnerability. As noted in the previous paragraph, I'm not much impressed by the risk from steam line breaks, but any reasonable thing that can be done to improve auxiliary feedwater reliability is worth doing. It isn't line breaks that are the real concern in PWRs, it is losing all feedwater capability and having no way to remove the afterheat except feed and bleed.

Sincerely,

Joseph M. Hendrie

JMH/dt

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

August 5, 1985

Docket No.: 50-206

Dr. Robert J. Budnitz
Dr. Joseph M. Hendrie
Dr. Herbert S. Isbin

Dear Gentlemen:

SUBJECT: RESPONSE TO SPECIFIC COMMENTS MADE BY NRC STAFF CONSULTANTS ON THE SAN ONOFRE NUCLEAR GENERATING STATION UNIT 1 INTEGRATED PLANT SAFETY ASSESSMENT REPORT

References:
(1) Letter from R. J. Budnitz, FRA, to C. I. Grimes, NRC, dated June 4, 1985.
(2) Letter from J. M. Hendrie, BNL, to C. I. Grimes, NRC, dated July 19, 1985.
(3) Letter from H. S. Isbin to C. I. Grimes, NRC, dated May 8, 1985.

Enclosed for your information is the staff's reply to specific questions and comments raised during your review of the draft NUREG-0829, Integrated Plant Safety Assessment Report for Southern California Edison Company's San Onofre Nuclear Generating Station Unit 1.

The staff is revising the affected sections of the report to reflect your comments on the issues and to correct editorial errors. The staff will also address the TMI and USI items applicable to San Onofre 1, which served as a basis to delete SEP topics, in a safety evaluation report supporting the conversion of a Provisional Operating License to a Full-Term Operating License.

Sincerely,

Christopher I. Grimes

Christopher I. Grimes, Chief
Systematic Evaluation Program Branch
Division of Licensing

Enclosure:
As stated

cc w/enclosure:
See next page

Section 4.1 (Topic II-1.C), Offsite Hazards

Comment

"In section 4.1.1 the text cites that SONGS-1 "calculated" a frequency of 4.5×10^{-6}/year for exceeding 0.5 psi overpressure for nearby explosions. Then it goes on to say that SRP section 2.2 allows a licensee to sharpen his pencil if the calculation exceeds the acceptance criterion. This pencil-sharpening was dutifully done and "sufficient conservatisms" were identified to warrant a no-backfit decision. I believe that the text would be strengthened if the conservatisms were identified briefly in the text. What are they? Why didn't SONGS-1 get a lower number at first, especially if they know that the acceptance criterion is 1×10^{-6}/year? Are the arguments really "qualitative", as stated in the text, or do they include certain quantitative arguments as well?" (R. Budnitz)

Response

The SRP guidance defines design basis events external to the plant as those accidents for which a realistic estimate of the annual probability of exceeding 10 CFR 100 exposure guidelines is in excess of approximately 10^{-7} and for which a conservative estimate of this probability is in excess of approximately 10^{-6}. The licensee's overall analysis was judged by the staff to be conservative; this was based on review of analysis assumptions, application of data, etc.

In this evaluation, the staff qualitatively judged the overall nature of the conservatism in the analysis rather than attempt to quantify the individual conservatisms entangled in the simplifying assumptions. For example, the analysis assumes a radioactive release in excess of 10 CFR 100 limits if the stress in the weakest structural element exceeds its overpressure capacity; a very detailed and costly analysis could be performed to establish the radioactive releases associated with various structural failure modes.

For individual hazards, such as flammable gases, analysis assumptions were chosen to bound possible results, such as assuming an instantaneous puff release and that the entire quantity in the cloud is involved in the fuel-air reaction. Section 4.1.1 will be modified in the final report to include some of this discussion.

Comment

"My experience with these things is that toxic gas monitoring technology is none too good. The things alarm gratuitously and are constantly getting out of whack. If there is an automatic control room isolation based on toxic gas monitors, there is a steady stream of isolations. It is a non-trivial distraction for operators, and hence a safety consideration. If toxic gas monitors are to be required, which I do not advise, then let the Tech Specs recognize the nature of the technology and not ask too much. Canaries would be better." (J. Hendrie)

Response

As noted in Section 4.1.3, the staff is reviewing the licensee's evaluation of control room ventilation improvements in accordance with TMI Action Plan item III.D.3.4 with emphasis on the reliability of active components in the system. The staff's review of III.D.3.4 for San Onofre 1 is continuing. The staff continues to believe that toxic gas monitors offer the greatest risk reduction potential; however, the staff agrees that the reliability of the system design and effective operability requirements are important considerations.

It is interesting to note that there was a recent "toxic gas event" at San Onofre. The licensee believed that a tear gas cloud had been carried over the site from nearby Camp Pendleton; however, the Marine Corps stated that no maneuvers were being conducted at that time involving tear gas. While members of the operating staff experienced a burning sensation in the eyes and throat, they were still able to conduct their necessary functions such that plant safety was not compromised.

Section 4.6 (Topic III-3.A), Effects of High Water Level on Structures

Comment

"One already noted (in 4.2) is ponding loads on flat roofs. The other is groundwater level for design basis purposes. The staff wants an evaluation of groundwater at grade (taken to be 5 ft. MLLW) for short-term hydrostatic loads, and whether that would lead to physical plant modifications and if so, what and when. That is the usual SEP approach and is reasonable.

The abbreviation MLLW, by the way, stands for "mean lower low water" and not "mean low level water" (p. 4-7)." (J. Hendrie)

Response

Plant grade varies from + 11 feet to + 20 feet; the short-term hydrostatic load is to be evaluated at the appropriate level for each structure. For purposes of load combinations, +5 feet is used. As an alternative, the licensee may implement a groundwater monitoring program as was done at Ginna. The definition of MLLW will be corrected in the final report.

Section 4.14 (Topic III-8.A), Loose-Parts Monitoring and Core Barrel Vibration Monitoring

Comment

"As in other SEP reviews, it is found that installation of loose parts monitoring equipment would not reduce any risks enough to justify the cost. So the staff concludes nothing further is needed on this issue. I agree.

"The draft report is silent, aside from the topic title, on core barrel vibration monitoring. I assume that was found not to be cost-effective also." (J. Hendrie)

Response

Core barrel vibration monitoring was raised as an issue only for Combustion Engineering plants and was, therefore, resolved early in the topic review for San Onofre 1.

Section 4.11 (Topic III-6), Seismic Design Considerations

Comment

"An editorial nit: 'seismic Category I' rather than 'A', p. 4-10, last paragraph." (J. Hendrie)

Response

In the FSAR, for San Onofre 1 structures, systems and components were categorized as Seismic Category A, B, and C. Category A generally corresponds to what would now be classified as Seismic Category I, and included the containment, spent fuel pit, reactor auxiliary building, control room, switchgear and battery rooms, turbine support pedestal and the intake structure.

Section 4.18 (Topic V-5), RCP Boundary Leakage Detection

Section 4.21 (Topic V-11.B), RHR System Interlock Requirements

Section 4.26 (Topic VI-10.A), Testing of Trip System and ESF, Including Response Time Testing

Comments

"Under section 4.18.1.2, the staff position is that Tech Specs are "necessary to ensure operability of the leakage detection systems, and, therefore, timely detection of leakage from the reactor coolant system." While the licensee has agreed, I think this may be overkill. Is a Tech Spec really necessary to ensure that these systems will work? How much unavailability is tolerable?

How much would occur without Tech Spec changes, and how much 'better' will the availability be with them? I don't know the answer to these questions, but I suspect that whatever problems will occur (with only low likelihood) are not likely to be improved by writing Tech Specs into the license. I think an analysis of what the sources are of residual unavailability might reveal that Tech Specs won't achieve the desired result. Has there ever been any other analysis of how Tech Specs affect availability of leakage detection systems?" (R. Budnitz)

"The discussion under 4.21.2 (overpressure protection of RHR system) concludes that the current configuration was acceptable although it deviates from current licensing criteria. However, the staff desires to impose a Tech Spec change "to provide protection for the RHR system". This is another example of overkill -- regulatory actions with little safety benefit, done for the sake of themselves. I would not make a Tech Spec change here." (R. Budnitz)

"The conclusion under 4.26.1 is that response-time testing of the RPS is not required. This is based in part on the sufficiency of functional testing, and partly on the low risk significance found by the limited PRA study. However, the staff wants Tech Spec changes to cover RPS testing anyway! The licensee agreed. This is still another overkill example in my view....the testing is in plant procedures already, isn't it?" (R. Budnitz)

"Primary Leak detection.......Operability of the leakage systems was felt to require Tech Spec provisions. I am generally against adding to the Tech Specs, but the requirement here is consistent with previous SEP practice...."
(J. Hendrie)

Response

The existing plant Technical Specifications contain surveillance requirements and limiting conditions for operation for the safety systems. The SEP philosophy regarding technical specifications is to recommend changes only when there are no clear surveillance requirements or limiting conditions for operation for systems that provide a direct protection or accident mitigation function. These systems are usually not used during normal plant operation such that their operability cannot be periodically verified except as required by the technical specifications. It is our intent that the details of the surveillance can be included in the plant procedures. In some cases, we have recommended limiting conditions in the technical specifications in lieu of certain design features required by current criteria; e.g., RHR overpressure protection. In such cases, the technical specifications can establish enforceable operational constraints to avoid situations which would otherwise require hardware modifications to achieve a comparable margin of safety. All of these recommended changes are consistent with those implemented for other SEP plants.

The NRC has initiated a generic review to address the policies associated with the role and content of technical specifications. Should this program result in recommendations to modify the scope of technical specifications, such changes would be applicable to SEP-initiated technical specification changes as well as those already in the technical specifications. However, we believe that the technical specification changes recommended in SEP are sufficiently simple and straightforward that they should not be substantially changed by this effort.

Section 4.24 (Topic VI-7.B), ESF Switchover from Injection to Recirculation

Comment

"The outcome of this assessment is excellent. I think this issue demonstrates well the value of the SEP review, since an important improvement has been achieved at little cost. The setpoint change for the RWST is just the proper approach to give more time for manual action if needed.

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However, the PRA analysis, while fully correct, cites an accuracy that is a little greater than justified by the analysis itself. The 'factor of 7' must be taken with a grain of salt, in my view, since the input numbers include some whose accuracy cannot be very great, such as the OPE1 and OPE2 values cited in the PRA analysis (page 59)." (R. Budnitz)

Response

The PRA analysis in Appendix D concluded that redundant annunciated RWST level instrumentation would result in a factor of 7 reduction in core melt frequency. The staff recognizes the uncertainty in the input. This was one of the factors leading the staff to recommend automatic termination of flow rather than just installing an additional level alarm.

The setpoint change would provide more time for operator action. However, since the time is still short and, since the charging and refueling water pumps are needed for long-term recirculation, the staff concluded that additional actions were appropriate.

Section 4.28 (Topic VII-3), Systems Required for Safe Shutdown

Comment

"The auxiliary feedwater questions started with whether the unit had a sufficient supply of water for the AFW in seismic Category I tanks. The licensee installed a large, Category I condensate storage tank to solve that problem. Next was the question of a passive failure of the suction line from the condensate storage tank; the licensee installed a redundant flow path to fix that. The licensee has also agreed to put in a third AFW pump, electrically driven. In the post-Davis Besse climate, one might look to expediting the schedule a bit." (J. Hendrie)

Response

The third auxiliary feedwater pump, with power from the dedicated diesel generator being installed for fire protection, will be installed during the outage beginning in November 1985. The balance of the third auxiliary feedwater train will be installed during the following outage. In view of the complexity of this modification, the staff believes this schedule is sufficiently prompt.

Section 4.32 (Topic IX-3), Station Service and Cooling Water Systems

Comment

"Something has piqued my curiosity. Under 4.32.4, the text states that "the licensee has determined.....that the tsunami gates need not be closed to prevent site flooding in the event of a tsunami.....Accordingly, the licensee has removed the tsunami gates." What I'm curious about is what might have changed to bring about this conclusion? Do we now think tsunamis at that site are smaller than was thought when the tsunami gates were designed? Or are the gates ineffective? Is the reactor higher than thought, or its critical equipment more protected? The text doesn't say." (R. Budnitz)

Response

The tsunami gates were originally installed to provide the ability to isolate the plant from the high water level generated by the tsunami. Since 1967, many changes have been made in the site flood control features, such as the north channel drainage ditch. When other concerns related to the tsunami gates arose, under SEP Topic II-3.B.1, concerning how long the gates should be closed, warning time, where cooling water would be discharged, etc., the benefits of closing the tsunami gates were reevaluated. The runup through the intake and connected passages would not be high enough to result in flooding in the plant yard. Therefore, the licensee has removed the gates. The IPSAR text will be clarified in the final report.

Section 4.33 (Topic IX-5), Ventilation Systems

Comment

"I find the resolutions of all the items in this section acceptable. I wish to point out that almost every one of the SEP reviews has found important differences between the ventilation systems in place and those desired for safety reasons. The changes have mostly been made, or will be. Has the staff learned a generic lesson here and asked any other licensees to look at these ventilation systems?" (R. Budnitz)

Response

The staff has reviewed all of the corrective actions resulting from SEP in the context of developing a program to extend this experience to other operating reactors. Of the 137 topics evaluated in SEP Phase II, the staff has identified 27 for which there were meaningful plant improvements, including ventilation systems. This experience was described in a report to Congress and is a fundamental part of an Integrated Safety Assessment Program (ISAP), which will replace SEP, described in a Commission policy statement dated November 15, 1984 (49 FR 45112). An ISAP pilot program has been initiated to develop the procedures by which the SEP lessons can be combined with pending licensing requirements, probabilistic insights, generic issues, and operating experience, and extended to other operating reactors.

Comment

"Several locations of safety-related equipment were found vulnerable to single failures in ventilation systems, and possible overheating of the equipment in that event. The auxiliary building and the charging pumps were the first issue. A limited PRA showed low risk significance, however, and the licensee's evaluation was that containment purge and exhaust fans could be used in a pinch. It's

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not clear to me how, if the charging pumps are in the auxiliary building, the containment purge is any help. Or, if the charging pumps are in containment, why auxiliary building ventilation system is of interest vis-a-vis the pumps. Or, finally, whether it is a good idea to have to run the containment exhaust system in order to keep the charging pumps operable. On the other hand, if charging pump failure doesn't amount to much, none of that is relevant." (J. Hendrie)

Response

The charging pumps are located in the reactor auxiliary building (RAB). An air-handling supply unit is provided for the RAB. The exhaust from the RAB (and from other buildings) is routed to the containment exhaust ventilation fans and from there to the vent stack. If the supply fan fails, the large containment exhaust fans will still maintain air flow and thus negative pressure the RAB. The containment purge lines are isolated during normal operation so the exhaust can be run without drawing from the containment atmosphere.

Section 4.34 (Topic IX-6), Fire Protection

Comment

"The licensee has proposed a dedicated shutdown system to solve assorted Appendix R issues. The details are still in staff review (a year after submittal, I point out) by the fire protectors. The SEP issue is, in effect, transferred to the generic Appendix R effort and declared closed for SEP purposes. That is OK, but the proposed dedicated system is of more than passing interest in several SEP topics and it is not a satisfactory situation to have agreement on that system hanging open for an extended period. If the fire protectors can't get around to the San Onofre 1 matter, it should be assigned to the SEP group." (J. Hendrie)

Response

For San Onofre 1, the date for compliance with Section III.L of Appendix R is April 30, 1986. The dedicated system will be installed during the refueling outage which begins November 30, 1985. The staff's review is continuing with the intent of supporting the licensee's schedule.

General

Comment

"In my opinion, SEP has achieved its objectives, with the remaining task of establishing with the licensee a 'living schedule' for integrating 'all issues yet to be fully demonstrated. A start was made with the Big Rock Point Plant, and hopefully progress is being made for the SEP supplements which are needed to complete the reviews of the ten plants. The 'living schedule' must go beyond SEP-identified issues and must include the

Unresolved Safety Issues, the Three Mile Island Action Plant Items, other generic issues, and opportunities for plant-initiated improvements. Improvements for extending plant life, for increasing plant reliability (and hence safety), and resolution of problems associated with aging need be given appropriate priority. Flexibility must be provided in scheduling items, and due attention given for best use of both plant and NRC resources." (H. Isbin)

Response

The licensee has developed an "Integrated Living Schedule" to establish priorities for plant improvements including SEP, TMI, and other regulatory requirements. Plant reliability is one of the factors considered. As with integrated schedules on other operating plants, flexibility is provided to account for unexpected delays or for completion of new higher priority items. A separate but related program has also been established for plant-initiated improvements.

Comments

"I view the NRC's Systematic Assessment of Licensee Performance (SALP) report as a key indicator of good management of the San Onofre units, although not enough details are given to single out performance with Unit 1. The trending of the ratings are available." (H. Isbin)

"I have one explicit comment about the text. On page 1-8, there is a discussion of NRC's SALP review. There are three categories in which the SALP board's conclusions are set down. The report (pages 1-8 and 1-9) indicates that there were five areas falling under category 1 and five falling under category 2. I believe the report would be strengthened if there was an explicit statement that no areas fell under category 3. This is in the nature of giving credit where credit is due. My modification would be simply to add "Category 3: none" to the text on page 1-9." (R. Budnitz)

Response

As all three units are on the same site, with many aspects having common elements (e.g., security, emergency planning, fire protection), separate SALP ratings for Unit 1 were not established in the SALP report. Since the previous rating period, ratings in 4 areas improved and ratings remained the same in the others.

The suggested modification to page 1-9 will be made in the final report.

Comment

"Some of the early experience revealed design problems that were solved after they were discovered. This is a natural course of events. There is no indication from what I read in this report as to whether the 'lessons learned' from the problems were sent around to other plants so that they too could profit from the experience. I hope that this was accomplished but cannot be sure --- and in fact I am not at all sanguine that this happened, considering that the design flaws were mostly discovered many years ago, before there was an acceptable industry-wide system for disseminating such information.

One apparent design flaw was overloading of cable trays, leading to the fires in 1969 that shut down SONGS-1 for about 6 months. The cable trays were extensively re-done after the fires and presumably the problem is gone. Was this lesson learned by other plants too?

Another apparent design error was revealed in early 1975. The failure of either one of the two feedwater pump discharge valves to close could have sent safety-injection water to the steam generators instead of to the reactor vessel. This problem was fixed once recognized, but did constitute a possible compromise of the plant's safety-injection capability under certain circumstances. Again, it is worth asking if this problem was analyzed and the analysis sent to all other relevant plants?" (R. Budnitz)

Response

At the time of the first event (cable tray fire) the systems for communicating such problems were not as developed as they are now. Many of these older lessons were later addressed in related generic reviews; for example, cable tray loading was part of the fire protection reviews conducted on all operating plants. Other older lessons are referred to in IE Bulletins as part of the evolution of operating experience. The second problem was unique to San Onofre 1 because of the design of its safety injection system.

As described in the response under Section 4.33, the staff is initiating an Integrated Safety Assessment Program which would combine the SEP experience with a wide range of other safety issues, including operating experience. Concurrently, the staff is continuing its efforts to improve the process by which design flaws and operating experience is evaluated and disseminated.

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16. ABSTRACT *(200 words or less)*

The Systematic Evaluation Program was initiated in February 1977 by the U. S. Nuclear Regulatory Commission to review the designs of older operating nuclear reactor plants to confirm and document their safety. The review provides (1) an assessment of how these plants compare with current licensing safety requirements relating to selected issues, (2) a basis for deciding on how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety.

This report documents the review of San Onofre Nuclear Generating Station, Unit 1, operated by Southern California Edison Company. The San Onofre 1 facility is one of 10 plants reviewed under Phase II of this program. This report indicates how 137 topics selected for review under Phase I of the program were addressed. Equipment and procedural changes have been identified as a result of the review.

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